SITING COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                )
                                 )
EXAMINING CRITICAL ISSUES IN     ) Docket No.
THE LICENSING OF THERMAL POWER   ) 00-SIT-2
PLANTS and RELATED FACILITIES    )
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CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

SACRAMENTO, CALIFORNIA

THURSDAY, FEBRUARY 8, 2001

10:07 A.M.

Reported by:
Valorie Phillips
Contract No. 150-99-001

COMMISSIONERS PRESENT

Robert A. Laurie, Commissioner, Presiding Member

Robert Pernell, Commissioner, Associate Member

Ellen Townsend-Smith, Advisor

Scott Tomashefsky, Advisor

STAFF PRESENT

Richard Buell

Joe O'Hagan

PUBLIC ADVISER

Roberta Mendonca

ALSO PRESENT

Edward Anton, Interim Executive Director
Craig M. Wilson, Chief Counsel
State Water Resources Control Board

Kamyar Guivetchi
Douglas K. Osugi
Department of Water Resources

Wayne J. Hoffman
Duke Energy North America

Brian F. Waters
Duke Engineering & Services

John S. Maulbetsch
Consultant

Michael B. Jackson, Attorney
Regional Council of Rural Counties

Michael DiFilippo
Water & Wastewater Process Improvement
Consultant

ALSO PRESENT

Gerald H. Meral
Planning and Conservation League

Kaitilin Gaffney
Center for Marine Conservation

I N D E X

P R O C E E D I N G S

10:12 a.m.

PRESIDING MEMBER LAURIE: Ladies and gentlemen, good morning and welcome. My name is Robert Laurie, Commissioner at the Energy Commission. Myself, along with my colleague to my right, Commissioner Pernell, make up the Commission's Siting Committee.

And the purpose of today's meeting is a furtherance of our series of workshops on potential barriers to long-term generation prospects in the State of California.

Further introductions, to my left is my Advisor, Mr. Scott Tomashefsky; and to Commissioner Pernell's right is Commissioner Pernell's Advisor, Ellie Townsend-Smith.

I think perhaps -- first of all, do you all have agendas? Are agendas available? Thank you. My intent is to ask Mr. O'Hagan or other staff to offer introductory comments and introduce our speakers for this morning.

Before we do that, Commissioner Pernell, did you have any comments you'd like to make at this time, sir?

COMMISSIONER PERNELL: No comments.

Just welcome, everyone, to the Commission and we look forward to a very informative workshop today.

PRESIDING MEMBER LAURIE: Joe.

MR. O'HAGAN: Thank you, Commissioner --

PRESIDING MEMBER LAURIE: Just a warning. Our microphones work in such a fashion that you darn near have to get intimate with those things.

(Laughter.)

PRESIDING MEMBER LAURIE: So gain your familiarity now.

MR. O'HAGAN: Thank you, Commissioner. My name is Joe O'Hagan; I'm a staff member at the California Energy Commission.

To my left, far left, is Craig Wilson, Chief Legal Counsel for the State Water Resources Control Board. And to my immediate left is Ed Anton, also with the State Water Resources Control Board.

And to my right is Kamyar Guivetchi, Department of Water Resources. And there's Wayne Hoffman of Duke Energy and Brian Waters of Duke Energy, as well.

These are this morning's speakers. Staff had prepared a short paper talking about water supply issues in California. It was really a gloss on the issues, trying to identify some of the issues associated with different water sources, opportunities for water conservation and wastewater discharge, as well. The focus was on water supply in response to the order instigating the investigation.

Staff's perspective is that looking back on our siting case history is that most water supply proposals that we've dealt with are workable. But one of the big constraints that I've seen, certainly, personally, is the lack of information.

Certainly the water supply in California is a great concern to many people. And the siting cases, as the Committee's aware, where public concern always addresses the water issue.

And one of the problems that staff has dealt with is that of acquiring sufficient information to be able to do a full analysis of the proposed water supply to projects, as well as alternatives. Because certainly there are alternatives available to any water supply proposal in California.

And I think that we do have some numbers in the staff water supply paper that are in terms of water use by power plant generation in California that are vague estimates, but I could honestly say I don't think it's a very large percentage. Certainly not in comparison to other agriculture or urban water demand in the state.

But, once again, there can be local impacts from the proposed water supply; and once again, it's certainly a concern for the local community for power plant proposals.

And with that I'd like to turn it over to Mr. Anton.

MR. ANTON: My name's Edward Anton; I'm the Acting Executive Director for the State Water Resources Control Board.

PRESIDING MEMBER LAURIE: Thank you, sir. We very much appreciate you being here this morning.

MR. ANTON: Certainly. I do want to say that we have another meeting that's going on at a parallel time, and both Craig Wilson and I would like to leave after we get through with our portion of this so we can attend the other meeting. We have two staff --

PRESIDING MEMBER LAURIE: Everybody

seems to be in multiple meetings these days, so please, feel free.

MR. ANTON: We do have two very knowledgeable staff counsels here who can stay longer, and answer questions should they come up at a later time.

PRESIDING MEMBER LAURIE: Thank you.

MR. ANTON: The State Water Resources Control Board and the Regional Water Quality Control Boards that we work with regulate two aspects of the water.

The first is water supply, which seems to be the main thrust of your workshop today; although on your agenda you do mention water quality. We also regulate water quality in the state, principally through the Regional Water Quality Control Boards under overall guidance from the State Water Resources Control Board.

From the water supply standpoint much of the impact is from a policy that the Board adopted some time ago that attempts to define where water for power plants should come from. The principal push of that was recognition that the state has a limited water supply.

I know you'll hear later from the

Department of Water Resources about the problems with the state's water supply.

But, simply said, we, in California, use more water than we have. And one would wonder how we can do that. A major factor is we're mining our fresh water from groundwater. And at some point that will have to stop, and we'll have to either permanently reduce the amount of water, or somehow find sources such as desalting, which typically takes a lot of power to do.

So the state did adopt a policy that set up a priority list of pushing use of waters that might not otherwise be used for the state's water supply first. And it does set up a priority, water that might have been discharged -- wastewater that would be discharged to the ocean, and thereby lost, other saline waters, the ocean, itself, for once-through cooling, and at the last of the priorities would be other fresh water supply sources.

That policy was not set up as an absolute, and it's recognized by both your staff and the state board that if all else is given and the analysis is thorough, that the water supply should not be an impediment to the siting and development of a power plant.

In any case, though, it does call for a look to determine if some alternative's available to reduce the amount of water.

That policy also includes provisions for disposal of wastewater from power plants, principally aimed at blow-down from cooling systems. As you're certainly aware, a water-based cooling system that relies on evaporation, concentrates the salts in that water.

If a cooling system of that sort is located inland, there is often a problem with the disposal of the waste because of the water quality considerations of that blow-down water. The policy calls for disposal to salt sinks or lined ponds. Other alternatives, of course, would be to a wastewater system that discharges to the ocean.

But, in any case, disposal of the wastewater is a problem that does need to be considered if evaporative cooling is a portion of the process.

I'll talk just briefly about the water quality aspects. In California we administer the federal program of the national pollutant discharge elimination system, which is a federal permit program for all discharges of waste to navigable waters.

The USEPA has established rules for power plants. And also the federal law requires states to adopt water quality standards for various types of discharges, or various types of pollutants. And the state has adopted a water quality control plan for the discharge of thermal waste. In most instances it would apply. It's for the ocean, or coastal waters, interstate waters and estuarine waters.

There are also standards for thermal waste for discharge to inland waters contained in water quality control plans adopted by the Regional Water Quality Control Boards.

PRESIDING MEMBER LAURIE: And who adopts those standards? That's your shop that does that?

MR. ANTON: The state board adopts the overall standards that apply statewide. And that includes -- there is an existing policy, or water quality control plan for thermal discharge that applies to ocean waters, interstate waters, estuarine waters and other tidal type waters.

But that does not apply to some inland waters, and we'd have to rely on the water quality control plans adopted by the Regional Water Quality Control Boards, which are subsequently approved by the state board before they go into effect.

An interesting thing about water quality standards for the discharge of heat, the Federal Clean Water Act includes a provision, which is section 316(a) of the Act, that essentially says you can waive all the thermal standards as long as you can show the balanced population of fish, shellfish and wildlife -- balanced indigenous population of fish, shellfish and wildlife can be supported on the water body where the discharge occurs.

And that particular provision is incorporated into the state thermal plan as an exception process.

The difficult thing about that, when we were talking about siting a facility in the short term, is to make such a showing takes a fair amount of time to develop the studies necessary to support that showing.

Many power plants have gone through that process and at present are operating under those types of exception, or are in the process of getting one.

For instance, the Moss Landing Power Plant was granted such an exception by the Regional Water Quality Control Board. That exception is now at the state board for its approval.

The federal law also sets up a section called section 316(b) that talks about cooling water intake structures. Basically calls for the best cooling water intake technology.

At the present there have not been regulations that dictated how it was done, and the regional boards have dealt with it on a case-by-case basis.

The USEPA has proposed regulations on that which are fairly difficult to comply with, I guess is the best way to put it. Basically it would force the use of something other than once-through cooling in all circumstances except where the cooling water was drawn from the open ocean. And this would only apply to new units or new intake structures.

At this point it's a proposed regulation. Because it falls under the basic provision of all the federal regulations, they've been held sort of in abeyance until the new administration can move in and review what's being done. So we don't know what will happen.

But the point being that if it were instituted as it is, a new cooling water system proposing to use once-through cooling, if it were not located offshore in the open ocean, would essentially be forced into something other than once-through cooling.

In adopting the NPDES permit for a discharge from a power plant, there are, of course, requirements placed on all sorts of pollutants that might be originating in the power plant. They are generally not difficult to comply with, but they do have to be addressed and the region --

PRESIDING MEMBER LAURIE: Let me -- I'm sorry, I'm thinking a little slowly this morning. On the question of once-through cooling, --

MR. ANTON: Right.

PRESIDING MEMBER LAURIE: -- is that the most commonly used technology today for gas fired plants?

MR. ANTON: I believe it is, but somebody from the Commission probably could answer that.

MR. O'HAGAN: Probably in terms of megawatts for our larger facilities, I would say yes, and certainly older facilities. And that's why we're seeing a lot of them being repowered.

Certainly in new generation from the 1970s on it has actually been cooling towers, wet cooling. You know, I think probably Diablo Canyon might have been the last once-through cooling facility approved in the state -- the Moss Landing repower certainly.

MR. ANTON: And so it's sort of an interesting comparison if you look at the nuclear plants that are operating. San Onofre uses a system where it does draw from offshore and discharges offshore. That's the type of a system that under the proposed 316(b) regulations would essentially be required.

Diablo Canyon, on the other hand, draws from the shoreline. And under the proposed regulations that would probably not be allowed, because they sort of separate the locations and --

PRESIDING MEMBER LAURIE: So, can Diablo do -- would they need to modify?

MR. ANTON: No. It applies to -- if the

regulations were promulgated as proposed, it applies to new intake structures.

Now, again, looking at the water effects of those two facilities, both of them have had concerns raised about them. Diablo does heat Diablo Cove, and based on my discussion with the executive officer from the central coast region, the biota of Diablo Cove has been altered by that discharge, and basically changed to more of a warm water situation. But I think that was expected when it was permitted.

COMMISSIONER PERNELL: What about water supply for inland plants?

MR. ANTON: Well, essentially if you're talking about using a evaporative cooling system, depending on the type of the power plant, they can use a lot of water.

If that's the proposal, and the desire to get a new water right, for instance, to take water from a surface watercourse, that would take a long time to obtain. Water rights are -- well, much of the water is already used up, it's already appropriate to others. And the process of getting a water right, it's a long process.

If they would go to some other source,

for instance an irrigation district that might already have a water right, and buy water from them would be a better solution. That would fall under the state board's policy, and they would need to show that that was the most economically and environmentally sound proposal to go with.

And, again, on the inland, if they use evaporative cooling they would also have to worry about disposal of the cooling tower blow-down.

COMMISSIONER PERNELL: And what happens to that? I mean they would have to worry about the disposal, but typically where does that go?

MR. ANTON: Well, if it's inland the existing plants, or plants that were operating, I'm thinking of Rancho Seco, they were required to blow down a fairly large amount to keep the salt, the salinity down.

On the other hand, if they were located, for instance, in the desert and they might be pushed to use as many cycles as possible, concentrate the salts in the tower, and then discharge a smaller amount of water to line the evaporation ponds. So the salt would be protected from the existing usable groundwater.

MR. O'HAGAN: If I can interject,

Commissioner, we have power plants that discharge to evaporation ponds like Mr. Anton said. And we have power plants that discharge to actually the local sewer system.

We have facilities that inject the wastewater into the groundwater through injection wells. And we also have facilities that don't have any wastewater discharge at all, zero discharge facilities where the water is recycled and, if you will, distilled off. And then that leaves a solid cake of salts. And then the water, which is fairly pure, is reused.

COMMISSIONER PERNELL: So it kind of depends on the facility and the geographical location as to what system is used?

MR. O'HAGAN: That's correct.

MR. ANTON: I think I've pretty much covered what I initially wanted to say. Mr. Wilson, do you have anything that you'd like to add?

MR. WILSON: Yes, I have a few comments to make. For the record my name is Craig Wilson; I'm the Chief Counsel of the State Water Resources Control Board. I'd like to thank you for giving us an opportunity to speak this morning. Also would like to give your staff some credit for juggling the schedule to accommodate us.

I'll also talk really briefly, before we get into some of the water issues, about a staff memorandum of understanding that was entered into between the Commission and the Board, I believe in 1998.

I can recall in the early '90s the Commission Staff came over and asked us, you know, maybe we need to have a memorandum of understanding to kind of coordinate our activities, making sure we're acting kind of on a parallel basis, so things aren't delayed.

And we kept more or less saying, you know, go away, there's not much happening in this arena. We've got other things to do. And finally I think they beat us into submission a little bit, and we entered into this agreement.

And now it's a very, in retrospect, it's very good that we have this, because I think it does give us a process to try to coordinate our activities and sort through some of these siting issues as they relate to both water supply and water quality. So, congratulations to your staff for getting us to come into that.

PRESIDING MEMBER LAURIE: Well, peer art does require patience, sometimes. Isn't that right, Mr. --

(Laughter.)

PRESIDING MEMBER LAURIE: Thank you, Mr. Wilson.

MR. WILSON: On the water issues, I think there's kind of a parallel between the water supply and the water quality in the sense that our two major policies that deal with these issues that the --

PRESIDING MEMBER LAURIE: Before you go further, on the MOU, we've gotten great cooperation from state agencies. Everybody is under a lot of pressure to work in a timely manner, and an effective manner in the approval process, and state agencies have been terrific in their cooperation.

So, I hope the intent behind that agreement is working to the point where if we need to talk about it again I would expect to hear about that.

MR. WILSON: Absolutely. Again, the two major policies that the state board adopted, and these were both adopted in the early '70s, the thermal plan which deals with water quality issues; and then the cooling policy that deals with mostly supply issues.

It's kind of interesting, they established some very broad general policies, and then there were not a lot of, you know, cases that happened after that to actually implement and flesh out the details and see how projects would comply with the policies.

They're written pretty generally. They both have some flexibility in them to, I think, address, you know, the energy issues that are present today. So it's just now, you know, 25 years after the fact, that we're really beginning to have cases coming up, interpreting some of the provisions in both of those policies.

I'll give you a couple of examples. On the cooling water policy, which was adopted back in 1975, there was a project up in Shasta County; I believe it was called Three Mountain Power Project, that raised some of the supply issues. It originally came before our regional board because it was an inland facility that the project proposing use of water supply from groundwater, and quite a bit of use of groundwater.

There was some water quality concerns about the disposal of the blow-down wastes and other things to the evaporation ponds.

But in the context of our regional board considering those, some of the interested parties to this project brought up this cooling water policy, saying, you know, wait a minute. This project's calling for large amounts of fresh water, fresh groundwater to be used. And the policy seems to state, you know, a preference that that's about the last resort.

And ultimately there was basically a settlement of that case. The parties got together and the project was redesigned such that it basically, you know, resulted in mostly a dry cooling situation. Much much less use of groundwater.

So, the policy worked in a sense to bring the parties together to work out a proposal that was satisfactory to everybody. I believe that project was certified.

Regarding the water quality, I think Ed handled those questions pretty well. I'll just touch on a couple of things.

On the issue of the intake structures

and the proposed USEPA regulations, in case your staff has not looked at them, they were proposed in the August 10, 2000 issue of the Federal Register. They are proposed regulations.

I believe the Bush Administration has already put out an executive order basically putting a hold on all proposed regulations, so we're not sure exactly what might come out of that. But if those regulations went forward intact they could potentially be a fairly significant constraint on new facilities, if the intake structures were either to rivers or lakes or to estuarine areas, because that's where the most stringent requirements would apply.

Probably the most significant current issue dealing with the water quality deals with the thermal plan, and it relates to which standards of the thermal plan applies to these projects that are being repowered or modernized. And I believe the Duke Energy representatives will probably speak to this issue.

But it makes somewhat of a difference in that when the thermal plan was adopted, certain standards applied to new facilities and certain standards applied to existing facilities which were basically grandfathered in.

Even the new facilities, if something is considered a new facility there is an exception to the requirements that Mr. Anton talked about, and that exception process was used in the Moss Landing situation such that alternative limits to the more stringent requirements were applied.

Other facilities, there could be a very good case made that certain other facilities in this modernization repowering are, in fact, existing discharges rather than new discharges. And we're kind of looking at these on a case-by-case basis.

We're looking at the Morro Bay plant right now to see in an overall sense whether the plant, even though there's been some modernization, you know, if the discharge place is the same, the volume is pretty much the same, there's probably some pretty good arguments to be made that that could be considered an existing discharge, and therefore subject to the grandfathered limits.

But, again, I think we're going to have to explore that on a case-by-case basis and make determinations.

So, with that, I think I've completed what I needed to say. Ed, do you have something?

MR. ANTON: Yes, there's one other thing I wanted to mention. First of all, I forgot to point out is that we are committed to cooperating with you to make sure that the projects do move ahead.

We recognize the urgency of the state's power needs and the need to help alleviate that. Recognizing all the constraints that we deal with, as well.

PRESIDING MEMBER LAURIE: Some of the various legislative proposals have us communicating to various officialdom throughout the land regarding any delay in our licensing process. And so we hate to waste paper. And so further cooperation is always a good thing to think about.

MR. ANTON: One other thing I wanted to mention about water supply, there is some discussion in your staff draft about the use of groundwater.

Ostensibly California doesn't regulate the use of groundwater through a water rights process. But there is a lot of water law and case law that relates to the use of groundwater, and probably the most significant thing is that if a use of groundwater that uses a lot, and a power plant can use a lot, might get in a case where it would tend to take water away from other water users of the same groundwater basin such that they would want to basically litigate over what's called correlative rights, and how the water is shared among all the users of the groundwater.

It can also fall under the courts of what might be considered an unreasonable use of water if it would take too much from other water users.

I only mention that to point out that while it might look like groundwater might be unrestricted in its use, it could be an impediment if somebody proposes to use a lot of groundwater in a basin where that might impact other people.

PRESIDING MEMBER LAURIE: How good are we, and maybe some of our other folks are in a better position to answer, at being able to geographically define underground basins? Can we do that with a great deal of skill?

MR. ANTON: Well, the fellow from Department of Water Resources probably could better answer that. But I believe most groundwater basins are pretty well defined. At least the ones that are major basins.

There are a lot of parts of the state where the groundwater is not very well defined, but those probably aren't basins that would have sufficient capacity to provide water for something like a power plant.

PRESIDING MEMBER LAURIE: Okay.

MR. ANTON: That's all I really have.

PRESIDING MEMBER LAURIE: Thank you. Mr. Wilson, I should note that 7558 sought to be litigated in our Pastoria case. The General Counsel's office wrote an excellent memorandum in defense of the Commission's actions in that regard.

If you have not had an -- and the litigated appeal was unsuccessful. So, to the extent that our Mr. Chamberlain can share his memo with you, it may be worth discussing.

MR. WILSON: We were familiar with that issue, and I actually talked to Mr. Chamberlain about that issue.

PRESIDING MEMBER LAURIE: Great, thank you very much. Gentlemen, we appreciate your time, thank you.

Mr. O'Hagan.

MR. O'HAGAN: Thank you, Commissioner. I just want to quickly point out that Three Mountain hasn't been certified, but it's getting close.

Also, too, in terms of the groundwater supply is that, as Mr. Anton indicated, most of the groundwater basins have been fairly well identified. There are some situations like we ran into with once again the Three Mountain project, where you have a fractured hard rock aquifer, and it is really hard to define that.

And also the situation is that there will be actually multiple aquifers in some situations like we find in western Kern County, where there's sort of a layer cake approach that, you know, there may be several aquifers.

And so identifying the extent of those and the interaction between the aquifers is often quite difficult.

PRESIDING MEMBER LAURIE: Thank you.

COMMISSIONER PERNELL: Thank you, gentlemen.

MR. O'HAGAN: I'd like to introduce

Kamyar Guivetchi from the Department of Water Resources.

PRESIDING MEMBER LAURIE: Welcome, sir, good morning.

MR. GUIVETCHI: Good morning, Commissioner Laurie, Commissioner Pernell, Commission Staff and the audience. I'm pleased to be here. My name is Kamyar Guivetchi. I'm with the Statewide Planning Branch of the Department of Water Resources. I've been at that position since last November and I look forward to this opportunity to come before your Commission and certainly share information regarding water and energy, which seem to --

PRESIDING MEMBER LAURIE: What were you doing before last November?

MR. GUIVETCHI: I was with the Department's Suisun Marsh mitigation program, and prior to that Delta planning and modeling.

PRESIDING MEMBER LAURIE: Great. Pleased to have you here.

MR. GUIVETCHI: Maybe before I jump into my presentation on the issue of groundwater basins I will note that the Department is currently undertaking the update of California's groundwater, or otherwise known as bulletin 118. The last update of that was in 1980. The next update, and a final update will come out in 2002.

However, we are right in the middle of developing a lot of that information which touches on looking at the over 500 basins and sub-basins, what their delineations are and how they can be characterized with the best data that we have.

And I would offer that if Commission Staff are interested, we can, at the staff level, begin sharing that information with you and hopefully provide you whatever resources that we have that you need to do your planning.

PRESIDING MEMBER LAURIE: I deeply appreciate it, thank you. Before you start I have to admit to a gross lack of expertise on underground water law.

I assume that law has been firmly established in California for 100-plus years. Is it fluid? Is it moving? Is it changing? Or do you have any sense of any of that?

MR. GUIVETCHI: I think the short answer is all the above. It depends on the basin and the aquifer. I am not a groundwater specialist. The other thing that I have, good fortune, is I do have a staff specialist here today, Doug Osugi -- Doug, raise your hand, please.

He is our program project manager on updating the bulletin 118. Doug, do you want to try to address that?

COMMISSIONER PERNELL: Would you come forward, please.

PRESIDING MEMBER LAURIE: Could you use the microphone, sir. And give us your name, please.

MR. OSUGI: Yes. My name is Douglas Osugi. And I'm the Program Manager for the update of bulletin 118, California's groundwater. And right now we're in the middle of like having our separate pairing. A lot of the information that's going to go into the update were aligned primarily on existing data that is now available, you know, since 20 years.

We have a draft map of the groundwater basins on our website that can be viewed, and we ask for comments from water agencies and such, and the public can send us comments on those basins.

We're in the process of characterizing those basins in terms of some basic geohydrological characteristics regarding water budget information on them, as much as we can, extraction data, and those types of things.

So we hope to get a published report out in 2002 looking for a draft of the report sometime this fall, a public draft. And we plan on having workshops, public workshops to be able to explain the bulletin draft at that time.

PRESIDING MEMBER LAURIE: I'm not going to ask for a discourse on groundwater law, but just in summary, if you have an aquifer that serves multiple ownerships, what's the rights and obligations of the parties?

Is use unlimited? Can you use it, but not waste it? Is it first come, first served? Do you have any thoughts about that?

MR. OSUGI: Well, normally, you know, I'm not, like I said, I'm not an attorney on groundwater law, but my understanding is that it depends on where you are, in what basin. Of course, if you have an adjudicated basin, basically the water has already been spoken for if it's gone through the court in that way, with a court-appointed watermaster.

If it's not in an adjudicated basin, then generally yes, it's really a first come, first served where the state board is not involved in that. It's usually left in terms of the local entities, the planning departments, to determine whether or not there's adequate water supply or groundwater supplies in the area.

The problem we're finding now through the bulletin 118 process and what's been known is that there's so much lack of information on the actual available and safe yield of some of these basins. So that's one of the things that were probably going to be part of Kamyar's presentation is that in terms of the enormous amounts of groundwater that could be used by these projects, they'd have to work with -- I suggest that they work with the local entities in the overall planning process in terms of competing uses for groundwater, as such.

And also protecting the resource in terms of recharge and those kinds of things. And as far as the disposal wastewater.

PRESIDING MEMBER LAURIE: Very good, thank you, sir. We appreciate your comments very much.

COMMISSIONER PERNELL: Thank you.

MR. GUIVETCHI: The only thing I would

add to that, and I'll touch on it later, is I believe the law is the owner of the overlying land essentially has access to the groundwater.

But I think there is an increasing recognition, both by groundwater users in their basins, and the Legislature, to encourage groundwater basin management planning so that while there's not a firm regulatory process on it, they are trying to get the locals to be more mindful of managing their basins efficiently.

PRESIDING MEMBER LAURIE: Okay, thank you.

MR. GUIVETCHI: I do have a presentation. Rick has promised to work --

PRESIDING MEMBER LAURIE: Well, I wish you well.

(Laughter.)

MR. GUIVETCHI: Actually, I think we've got to go, Rick, if you could hit the slide number one. I think you're toward the end.

Okay, I think we can start on the next slide. What I'd like to do first is I'd like to put this in the context, the information I'm going to present. I was asked to talk somewhat on near-term, long-term, water supply availability.

Certainly it's in relation to your interest in siting future power plants.

A number of people in the Department of Water Resources were provided copies of your staff paper on water supply; reviewed it. And all in all we feel that it's a very well framed, well written document.

The one editorial, I think there's a typo on page 3 in conjunction with the current average delivery of the State Water Project. It states it's 2.1 million acrefeet. I believe it's 3.1 million acrefeet. So just for that to be accurate.

What I will try to do is, as I'm making my presentation, identify the numbers that are in your staff paper to kind of show how they tie into our overall water picture for California.

The information I'm going to present to you is by and large what was put out as the update, the 1998 update to the California water plan.

The original, or first water plan, came out in 1957. There have been numerous updates since then. We are now in a five-year update cycle. The last two were in 1993 and 1998. And at the end of this presentation I'll give you a little bit more flavor about how we're planning to update the next one by 2003.

The plan is a master or strategic plan. And it's in the water code. DWR is responsible for putting out that plan, with input from water purveyors, users and suppliers throughout the state.

It does not have any implementation teeth. It's made clear in the water code that whatever is in the plan can only be implemented after additional appropriations and authorizations by the Legislature.

So, again it's a --

PRESIDING MEMBER LAURIE: Do you have to do an EIR on that plan?

MR. GUIVETCHI: No, we don't do an EIR because it is considered like a master or strategic plan. It is not an implementation plan.

COMMISSIONER PERNELL: You said it has to be approved by the Legislature?

MR. GUIVETCHI: No. My point was that if any of the recommendations in the plan were to be implemented, those actions would need additional approvals by the Legislature. And would have to go through an environmental review process on a site-specific basis.

So, this is again a very over-arching master or strategic plan. And basically the approach has been up to now to do an inventory of water supply, developed water supply in the state, water uses in the state, and show how those balance out. And if there are shortages in regions and in time. Different hydrologic conditions. And that's what I hope to share with you today.

So, basically we'll look at supplies uses. We'll look at a water budget with existing facilities and projects. Also kind of forecast into the year 2020 with what things might look with projects or actions that were deemed highly likely during the last process to update the water plan.

I'll also end up by touching on a few of the groundwater issues which I think we've already touched on. Also, the cost of water was one of your interests, or staff interests. And then I'll end up with a few recommendations.

Next, please, Rick.

PRESIDING MEMBER LAURIE: Will you be

able to provide hard copies of your slides for us?

MR. GUIVETCHI: I certainly will. We will provide electronic -- in fact, Rick has the electronic copy, Rick Buell. And those could be printed. I'll leave that file with Rick.

Did you want the copies right now?

COMMISSIONER PERNELL: No.

MR. GUIVETCHI: Okay. The purpose of this pie chart is to bring home an important point, and that is that the water plan and the water budget data that are reflected in your staff paper and are in the water plan don't cover or consider all the water that falls on the state through precipitation.

The large pie chart there represents about 200 million acrefeet in an average precipitation year. The two slices that have been moved to the side, those represent the surface runoff from that 200,000 acrefeet, which is roughly 71 million acrefeet. And the dark shaded pie is that portion which we call the developed water supply, and includes some groundwater, which is what's considered in or has been considered in the California water plan update, and is the basis of the data that I will present to you. And it represents about 57 million acrefeet.

So, the point here is it's not -- the supply and budget analysis that I'm going to present to you does not mean it includes every drop of water that falls on the State of California. It's considered to be that developed water supply that could be used for different uses at this time.

And what I will show is how that developed supply is then going to be, or is used, or separated into urban, agriculture and environmental uses.

Next slide, please. This is something we all know and it's just a point that the bar charts on the left are the average annual precipitation that fall in the different regions of the state.

We've separated the state into ten regions, each bar chart represents the average total precip that falls in that region. And as we all know, most of the precip and runoff occur in the northern part of the state versus the southern part of the state.

What this is to show is that the total pie chart in the previous is all the water of that

57 million acrefeet -- excuse me, 71 million acrefeet. And this shows how it's distributed throughout the state.

Next slide, please. We also know that in time there's quite a bit of variability. And this is all of the precip that fell in Januaries over the last number of years, and the faint, thin, horizontal line that you see there, that's the average.

So those pie charts that I was showing you, again, is for average conditions. And what we see is from year to year the average precip can vary quite dramatically both below and above the average.

Next slide, please. The ten regions here, we've kind of separated them out like a puzzle and the arrows that you see going between those regions, and the thickness of those arrows, are to show current water movement from one region to another.

And the numbers aren't so much important as the fact that while we get precip in these regions and we presented them that way, it in no way means that the water remains in those regions. In fact, through both natural courses, water courses, and human-made water courses, the water can be conveyed to other regions.

Now, an important thing -- a footnote to this is this is the capacity of water that can move. It doesn't mean that we could always move this much water whenever we want. There are regulatory, environmental conditions and constraints that will sometimes preclude being able to move this much water anytime that we desire.

PRESIDING MEMBER LAURIE: Those are simply physical and engineering constraints, it can be done?

MR. GUIVETCHI: Yes. This shows you the physical capacity for doing it.

PRESIDING MEMBER LAURIE: Okay, and --

MR. GUIVETCHI: Not the whether you could do it at any instant in time, moment in time.

PRESIDING MEMBER LAURIE: -- when you earlier mentioned the 200 million acrefeet that has not been utilized as part of our water system, how much of that would be feasible to develop if public policy demanded that it be done?

So, if a water emergency were declared

and somebody said we need to get more water on line. We have 200 million out there that's not being utilized, feasibly how much of that would be available for development, absent other public policy questions?

MR. GUIVETCHI: Okay, one clarification. The entire pie was 200 million acrefeet --

PRESIDING MEMBER LAURIE: I see, okay.

MR. GUIVETCHI: We are using, of that, 71 million acrefeet of surface runoff, and of that, 57 million acrefeet of the total 200 is what we consider the developed water supply.

Toward the end of my presentation you will see our projections of likely projects that could occur by the year 2020 that either through demand reduction or supply augmentation could increase water supplies in the order of a couple million acrefeet.

But, again, that's kind of still within that developed water supply wedge. Up to now we have not really actively considered moving into the smaller creeks which were the other runoffs, or the larger area which is just waterfalls and surface runoff where it percolates into groundwater.

I guess the theoretical question would be from an engineering point of view we can do a lot of things, but there are a lot of interests, concern that we don't want to adversely affect the environment in doing so.

So it's that delicate balance that we're going to have to look at.

Okay, next, please. This slide, it's a little difficult to read, but the point here to make was that of the total supply that we have, which is, if you notice, 77.9 million acrefeet, is that 78 million acrefeet which is in your staff's white paper or water supply paper.

So it's broken up by surface water contribution, groundwater contribution, recycled and desalted water. Of the surface water contributions a part of that is managed by the Central Valley Project, Colorado River Project and other federal projects, a part by the State Water Project.

Of the federal and state projects together, that only accounts for about 30 percent of the surface water resources, or the water supply, excuse me.

The point here is not that the state and federal water projects are not important; in fact, they are because of their storage and conveyance facilities and flexibility.

But the other -- what I'm really trying to point out is a lot of the water is controlled at the local level, which could be what you're going to be concerned with when you're looking at siting power plants.

So, 70 percent of the water supply is actually controlled at the local level. Not by the state and federal water projects.

And we see, of the total 78 million acrefeet of water supply, this is average again, average conditions, about 12.5 million acrefeet come from groundwater and about 300,000 acrefeet come from recycled and desalted water.

Next slide, please. This slide is that same total, about 78 million acrefeet, but just showing how it's distributed regionally amongst those ten geographic regions. And, again, this is pretty self evident.

Next slide, please. This slide, what I'd like to do is first draw your attention to the pie chart on the lower left. This is the existing or what was considered the 95 base conditions in the last update of the water plan.

And of that wedge, that dark wedge that is being considered in the water plan, this shows how it's distributed between urban, ag and environmental water uses. And what you'll see is that the urban -- excuse me, the agriculture and the environment are roughly the same, around 45 percent. And the urban around 11 percent of the total use.

So, --

PRESIDING MEMBER LAURIE: And what's included in the category of environmental?

MR. GUIVETCHI: Okay, that's a good point. Again, because we're only considering the wedge that's the developed water, this includes the wild and scenic rivers, instream uses, and water uses for refuges.

So it doesn't mean all the water that's used by the environment in California, because, as you noted, a large part of that large pie we don't even consider because it's not developed water.

So these are the waters that are running through developed water courses through the state, and can either -- which are either wild and scenic, or have some instream minimum water requirements for protecting the aquatic habitat, or are diverted to feed managed wetlands refuges.

Now, we've kind of shifted gears now. We went from supplies, and now we're looking at uses of that supply. The pie chart on the lower right is our projection of what things might look in 2020.

And what you'll note there, the numbers don't change appreciably, but there's a slight shift predicted from agriculture to urban. As population increases and ag lands are developed, the total distribution will change slightly from agriculture to urban.

Next slide, please.

COMMISSIONER PERNELL: Well, let me ask you a question on that.

MR. GUIVETCHI: Please.

COMMISSIONER PERNELL: Does that represent that in the last five years and the next 20 years that the environmental water allotment won't change?

MR. GUIVETCHI: What this suggests is if '95 was considered as the base year when the last update was done, and 2020 was the planning horizon, that for the developed water slice of the pie it was estimated that the needs of the wild and scenic rivers, instream uses, and uses on refuges would not change appreciably, that's correct.

COMMISSIONER PERNELL: Okay, and --

MR. GUIVETCHI: That's the assumption.

COMMISSIONER PERNELL: Okay.

MR. GUIVETCHI: Next slide, please. What we'd like to do now, we've talked about supplies, we talked about uses, we're now looking at budgets.

And so we're putting the two together. We have in the upper part of the table water use, again split by urban, ag, environmental total. These are the same numbers that were on those pie charts on the previous slide.

And then on the lower part of the table you have supplies which are surface water, groundwater, recycled and desalted, which is again a summary of the slides a few slides ago.

And we see that in our estimates for the 1995 level of development or base condition in an average hydrologic water year, those are a lot of caveats, that the shortage between the uses and the supplies was about 1.6 million acrefeet.

Now the footnote here is that much of that 1.6 million acrefeet was groundwater overdraft. Okay.

Now, the column to the right is the same analysis, but again for the projected planning horizon of 2020, and what you'll see is that the supplies don't change appreciably. But because we're assuming that population increases, the urban water use goes up, ag water use actually we assume would go slightly down, because if you recall we're assuming some ag lands will go out of production, and environmental water use stayed pretty much the same.

So that now, the new balance, because we have more uses and about the same supply with our existing facilities and programs, our shortage or shortfall we assume is about 2.4 million acrefeet. And that value, again, was in your staff's white paper.

Next slide, please. This is the ten regions again, and there are two sets of numbers. The blue numbers on top for each region are the average conditions, which is what we've been talking about. And what this is intended to show is of that total shortage of 2.4 million acrefeet projected for 2020, how would that show up regionally.

And what it shows is except for the Tulare Lake and the north Lahontan, all the others basically would not have -- I'm sorry. What this shows is that the shortage -- I was thinking of future programs, we'll get to -- what this shows is that the shortage is distributed quite differently throughout the regions of the state.

And again, because uses are tied to population and agricultural production and supplies generally are on the northern part of the state.

Next slide, please. Okay, now we'll shift and say what we did in the water plan is say by the year 2020 what options for additional demand reduction or supply augmentations might go into effect that could change the water balance.

And I'm not going to go into detail here, but essentially we're assuming -- we assumed that about a half a million acrefeet could be gained by reducing demands through water conservation, recycling, reclamation.

We looked at or assumed that we could increase local supplies, surface water, groundwater and maybe to your interest, you see that we estimate that there's going to be a significant increase in recycling and desalting water.

And because of the ability of power plants to use these waters, there might be an opportunity, even in the future, to tap in on these waters as the state board policy suggests, rather than looking for fresh water.

Because one of the things the CalFed process, and all water planning processes are emphasizing is really stress demand management up front, and then look for supply augmentation.

Now, that demand management, to the extent it results in recycling, may be a source of water that could be available for power plant siting.

PRESIDING MEMBER LAURIE: One policy issue that is going to come up in discussion of the use of desalinized water, I assume when you talk about the use of such you're talking about coastal use, is that right?

MR. GUIVETCHI: You're absolutely correct on the desalinization side. I was really emphasizing the recycling and reclamation side.

Because there the energy issue is not the same. And it's not kind of limited to coastal uses, you're absolutely right.

PRESIDING MEMBER LAURIE: Because the point being that, and it may even be true when you get to recycling, the use of recycled water or desalinated water suggests new power plant uses in heavily urbanized and coastal areas.

Well, there's other barriers to siting plants in urbanized and coastal areas. And so there will be increasing pressures to locate plants outside of these areas where such resources are not going to be available. So there is going to be conflicts.

MR. GUIVETCHI: Your point is very well taken. I'll just add, Commissioner Laurie, that a lot of the availability for drain water, reclaimed drain water does come from agriculture. So there could be less populated areas where there will be opportunities for reclaimed water through drainage.

And essentially, the bottomline of this slide shows that of the total options either through reducing demand or increasing supplies, we could look at about 2.2 million acrefeet by the year 2020.

Next slide, please. Now, if we take that and overlay it to what we had talked about with our existing programs and options, in this slide the 1995 column are the same numbers. They're there just for reference.

But you'll see that the 2020 numbers have now, the water uses have reduced somewhat, particularly on the urban side. And the water supply has been increased, so that rather than 2.4 million acrefeet shortage, we're now to about .2 million acrefeet shortage.

Next slide, please. And this is that same slide which I confused with the earlier one, showing that with these likely options in the year 2020, there would only be a couple of the ten regions that in an average water year may still have shortages.

The thing to note, though, that on each of those regions there's also a red number below the blue number, that is for a dry water year condition which I haven't really spent a lot of time talking about. But it does show that in those years there still could be some significant shortages.

Next slide, please. I'm now going to turn my attention to the issue of cost. In the water plan we haven't spent a lot of time or focus on water costs, but in the '93 update we did do a survey of what industrial water costs were by region on a per acrefoot basis.

And, again, it's kind of hard to read at that scale, but what you'll see is the wide variability of costs, anywhere from about $10 to $15 an acrefoot in Fresno to as much as about $1600 an acrefoot in Santa Barbara. And that's probably because of the desalinization option there.

Okay, next slide, please.

PRESIDING MEMBER LAURIE: On the question of the use of the environmental waters, I would guess that the regulatory scheme that provides for the use of such waters are a combination of both state and federal, is that right? Or is it mostly federal, or is it mostly state?

MR. GUIVETCHI: You mean the regulatory aspect of it?

PRESIDING MEMBER LAURIE: Yes.

MR. GUIVETCHI: They're both --

PRESIDING MEMBER LAURIE: Okay, and some fall under federal jurisdiction and some fall under state jurisdiction.

From a state perspective, to what extent do regulators view the -- I forgot what the numbers were -- 37 million acrefeet, no, or is that percentage -- how many million acrefeet are set aside for environmental use?

MR. GUIVETCHI: It was about 45 percent of the 57 million acrefeet.

PRESIDING MEMBER LAURIE: To what extent do you folks view that as a reserve? So that in cases of emergencies or extreme drought conditions or earthquakes or whatever, the rules could be modified for use of that water for either urban or agriculture.

Do the rules allow that? Who has jurisdiction? Do courts have jurisdiction? Does Congress have jurisdiction? Who ultimately controls the use of those waters?

MR. GUIVETCHI: You're treading on the periphery of my expertise. That might be a better question to ask the State Board --

PRESIDING MEMBER LAURIE: That's never stopped me, so feel free.

MR. GUIVETCHI: -- but to the extent that I have been involved in environmental review processes and permitting processes, generally environmental permits or environmental components of permits do not have an emergency provision in them.

What has happened, for instance when we've had major floods where levees have been damaged and we've had to go in and do emergency work, we've had to request an emergency review by the regulatory agency and authorization to do that work.

In some instances the Governor, like during the 1997 and 1998 floods, did provide some state level waivers for those conditions, but from the U.S. Fish and Wildlife Service, and even Fish and Game from the state perspective, we would go to them, and it's very prudent to go to them and work with them during the emergency, and say that these are the things we have to do, and we need your assistance to give us the permission to do it.

But it is on a -- to the extent that I know, on a case-by-case basis.

Okay, next slide, please. This is a

slide that shows the cost of pumping groundwater, again cost per acrefeet. And there are more bar charts, because what it shows is for each of those ten regions it shows a low and a high.

And, again, for instance on the north coast you can see groundwater pumping rates vary from $10 an acrefoot to about $50 an acrefoot. And it can go as high as $130 an acrefoot in the San Francisco Bay region and elsewhere.

So, again, electrical power costs for doing groundwater extraction differ depending on where you are.

Okay, next slide. This we kind of touched on a little bit. And this is the idea that while there are no regulations like we have on surface water, for groundwater there is an increased trend for groundwater basin users to work together to have management plans.

And this will work into one of my recommendations for this Commission. AB-3030 has worked to set up about 150 of those, and about 17 counties have already enacted groundwater management ordinances since '94.

So what this indicates is that as sitings for future power plants are looked at, it would be very good to work closely with the local entities, especially if they have groundwater management plans and ordinances.

COMMISSIONER PERNELL: Are those groundwater ordinances typically the same? Or do they vary widely between counties?

MR. GUIVETCHI: I believe they vary widely. Doug, do you have any input on that? Yeah, are the ordinances very different from county to county?

MR. OSUGI: Generally the ordinances -- just a little background on those ordinances that have occurred since 1994, a lot of them have to do with being implemented over concerns about potential export of their groundwater to outside the county area.

So a lot of the ordinances have provisions in there, conditional use permit type language that require anyone that wants to export groundwater out of the county to make sure that there are no negative or adverse impacts to the local area.

And that's kind of what's driving a lot of the implementation of these ordinances there. But the management plans have been going on for quite some time, and does show that there's a lot of interest in the management of the resources by the local entities.

MR. GUIVETCHI: Rick, can we have the next slide? I think it goes right into -- this is a map of the state and, again, I don't expect you to see all the detail, but an important thing is the yellow dots, which are primarily in the southern part of the state, those are adjudicated basins and --

PRESIDING MEMBER LAURIE: Adjudicated by whom?

MR. GUIVETCHI: By the courts. So at some point a court stepped in and worked with the locals on how the waters would be used and distributed --

PRESIDING MEMBER LAURIE: And that would have been the result of a petition filed by one owner when there's a contest?

MR. GUIVETCHI: Could be many different scenarios, but the point being is that in those cases if a power plant were going to be sited, there would be a much more formal process to get the ability to use the water, because it has been adjudicated.

The other dots that are there are these areas where ordinances have been set up and water management plans occur. And, again, those can be opportunities because what it could mean is if the people that are looking to develop or build the power plants set up early communication with the local basin managers, that they could find potentially a win/win. Especially through the reclaimed water aspect of it.

Next slide, please. Now, just a few overarching recommendations. I will have to note that the State Board Resolution 7558, while several years old, believe, still has a lot of insight and application by giving us some guidance on looking at using kind of the water conservation approach first, and then using the surface water or the fresh waters to the least extent possible.

And so I think that, as a guideline, is probably still a very good approach to consider in future siting of power plants.

The second bullet is unfortunately in the last few water plan updates we haven't worked closely with Commission Staff on looking at the nexus between energy and water. And I think as of late it's become very clear that there is a nexus, an important nexus.

And my recommendation is we need to, and I'll do my part, to work very closely with your staff to insure that the next update takes into consideration as many of these options and opportunities that we can.

It's a two-sided coin, because not only as we've been talking today, future sitings of plants may have a water supply impact, but some of the water conservation measures have an energy impact.

And so what we'll want to do is to try to find as few cases where we're hurting each resource by trying to help the other.

The third bullet is there's been a lot of effort by CalFed to help fix the delta, and many of the actions that CalFed is planning to do doesn't occur within the delta proper, but throughout the central valley and the southern water delivery service area of the state.

And one thing to be mindful is to make sure that future sitings of power plants in some way doesn't exacerbate those actions that are trying to fix the delta and other aspects of state water and environment.

And then finally, it's this idea that I've mentioned a few times, is it would be very prudent, especially on the groundwater level, but also because locals manage 70 percent of the state's developed water supply, to work very early and in a coordinated fashion with local managers, water management districts, in trying to plan and find opportunities for the power plant sitings.

And then just a few slides -- next slide, please, is to emphasize that we are in the next update of the water plan. And that we are approaching this in a much new and different fashion, partly because it's been required by new legislation that's modified the water code, and partly because I think we, as a Department, also believe that this is the best way to go.

We are striving for a much more collaborative consensus-based process with broad public input. And having an open, transparent process where we can share our assumptions, data and methodology with people as we're going along during the update process.

We have a public advisory committee that's close to 60 people with agency, water purveyors and a broad cross-section of water interests in California. And we also have an extended review forum that is between 100 and 200 people so far, who will also help us in this process.

And, again, I would hope that the Commission Staff becomes more engaged with us in this process.

Next slide, please. The timetable is by the end of this year we have to put out a roadmap of what our methodology and assumptions are. By early 2003 we will have to have a draft plan out that will go out for public comment and review.

And by the end of 2003 we will have the next update for the California water plan distributed.

And then the last slide, this is kind of just a flavor of things to come. If you notice in all the maps prior that I showed you they had ten large regions. When we do our data crunching they're actually done in these things called data analysis units. There are 275 or so in the state. Much more specificity in spatial definition.

And so what we hope to do is make the water balances that are done at that level readily available to people that would need them. And so if you're going to be siting power plants, that kind of information would be more useful than if you're getting data for a much larger area.

That concludes my presentation.

PRESIDING MEMBER LAURIE: And very nicely done. Question for you. And I'm going to ask for Bill Chamberlain's help on this. Bill, can I get you to a microphone.

On any individual project that comes before us, and we're doing our water analysis, and the question is, is there a significant impact. And that question would especially arise if the issue is contested.

You've indicated that I think 70 percent of available water is under the control of local jurisdictions. What is your understanding of what environmental data we should be using to determine whether or not the proposed project significantly impacts the water supply?

Am I framing the question satisfactorily, Bill?

MR. CHAMBERLAIN: Well, I'm not sure if I understood the question, so --

PRESIDING MEMBER LAURIE: Well, let me try it again. We're in area X and it's clear that there's some debate among the community as to where and how this water should be utilized. Over here wants it to be used 4000 acrefeet for the plant, the group over here wants to build a new community at the edge of the old community. And they argue that this 4000 acrefeet significantly impacts water supply.

What environmental documentation is available that allows us to say no, we have these documents, and these documents clearly indicate that there's no significant impact on the water supply?

It can't be the state water plan, because the state water plan doesn't have any environmental documentation attached to it.

Do the local districts, in adopting their plans, do environmental analysis that can be relied on?

MR. GUIVETCHI: I believe for their general plans, no. I think any city/county plan also is exempt from CEQA/NEPA because again it's not -- there's no implementation aspect.

One area that you could look to is CalFed certainly has done a lot of rigorous environmental review and analysis for the areas that it is concerned with, which would be the central valley and the southern water service area in California.

So, there are a lot of environmental review and documentations in areas that are the purview of CalFed.

I think any of these local water districts at some point will have done or would have to have done some kind of action that would require environmental documentation. So a good place to start, again this is going back to early communication with the locals, to contact them, find out what they've done, what information they have, what environmental documents they have produced.

I don't think there's any overall recipe or cookbook that you could use because I think the issues, the environmental issues will be very different depending on the site-specific conditions that you're going to be confronted with for any particular plant.

But I think there is a lot of information out there, and I would start with the people in the area that you plan to do the project, or proposing to do a project.

One thing that I didn't put up as a recommendation, but I think it's -- I'll add, anyway, is that it does look, from your staff paper, that you do have quite a bit of a range of technologies and flexibilities.

And one thing that you may want to consider, because of the highly variable water conditions in the state, between wet and dry, is provide yourself those options.

So options are combined wet/dry cooling options. What it does, when there's water you would use the wet side. And when we're in a dry period, drought year, rather than needing 2000 to 4000 acrefeet per year, you would fall down to the 60 to 200 acrefeet.

And so what it does, it gives your project proponents a lot of flexibility to weather those dynamic swings in California water. And that isn't going to change. We have a very spatially and in time variable precipitation pattern and runoff pattern.

So anything that you can do that can give you robust flexibility at any one plant would be helpful.

MR. O'HAGAN: If I can respond to the

question, too, Commissioner Laurie. General plans, updates, revisions do generally trigger a CEQA requirement. And also in terms of water district, they're required to do a master plan periodically. And there is a CEQA document associated with that.

And taking the High Desert Power Project as a case in point, Victor Valley Water District did do a master plan and a CEQA document. However, it was sort of a broad-brush, and dealt mainly with growth inducing and infrastructure requirements.

And working on the case the main concern there, of course, was the groundwater pumping effects on the Mojave River and endangered species, which was not addressed by that document.

However, the Commission did rely on the Victor Valley CEQA document in terms of addressing growth-inducing impacts from the project.

PRESIDING MEMBER LAURIE: So, are we -- this is a question: In almost all cases is there environmental documentation available, having been done by other entities, that we can rely on?

MR. O'HAGAN: No. And the case in point because --

PRESIDING MEMBER LAURIE: Did you say no?

MR. O'HAGAN: Yes.

PRESIDING MEMBER LAURIE: Yes.

(Laughter.)

MR. O'HAGAN: In many cases there's specific, taking groundwater as an example, hydrogeologic information and things. But in terms of doing well draw-down analysis, how the groundwater pumping is going to affect, contaminate groundwater, whether that's going to draw that to somebody else's drinking water well and things, generally we don't have that information.

And that's one of the big time constraints that we face, is collecting that information, doing the analysis. It's a lot of information, it's very complex issues generally, and it takes quite awhile.

And then I think sometimes you do see delays in the siting process because of that analysis.

PRESIDING MEMBER LAURIE: Thank you. Bill, did you have any additional thoughts on that question?

MR. CHAMBERLAIN: Yes. I think one of the recommendations that you heard this morning was that we need to work more on the overlap between energy needs and water needs, because one of the things that we saw in the High Desert Project was -- or actually in some of these projects we've seen people making the contention that use of water is a waste when you're using it for evaporative cooling.

And we found that if you just looked at the prices that we were seeing last summer for power, and looked at the efficiency penalty that dry cooling would have imposed, particularly on a plant in the desert, we were getting just enormous value for the 4000 acrefeet of water that was being employed there.

And you notice that when he put up the costs of water, some areas the cost of water is very low, and in other areas it's very high.

In this case I believe probably the value of water for cooling in that particular case was higher than any of those figures that were put up this morning.

PRESIDING MEMBER LAURIE: Thank you. Joe.

MR. O'HAGAN: Another point I'd like to bring out is that even though, and I could use High Desert as an example again, is that there are a number of adjudicating groundwater basins in the state, that generally those adjudicated basins there's really not a constraint on new groundwater development.

The situation with High Desert would be that even though it's been adjudicated, there's obviously been a lot of litigation associated with that. The project, there was no constraint on them putting in new wells to serve the power plant.

A number of the ordinances that we've dealt with for siting cases where the county has requirements in terms of wells, it's not also a constraint on groundwater pumping, just often it's their way of keeping tabs on what wells are going on and how much is being pumped, and specifically looking at public health concerns of the groundwater.

Our next speakers are Wayne Hoffman and Brian Waters of Duke Energy. They're going to talk about once-through cooling and cooling alternatives.

PRESIDING MEMBER LAURIE: Good morning, gentlemen.

MR. HOFFMAN: Good morning, Commissioners Laurie and Pernell. Thank you for the opportunity to be here today. My name's Wayne Hoffman and I'm Regional Environmental Manager for Duke Energy North America. To my right is Brian Waters with Duke Engineering and Services, one of our lead water consultants.

I feel like I may be talking about the wrong subject after all this discussion about inland water supply, but I would point out while I'll be focusing on the issue of coastal power plants, and water quality and water issues related to once-through cooling in my presentation, a number of issues have come up here today that deal with the question of water supply generally as it relates to inland power plants.

And I'd like to just take a minute or two at the end of my presentation to address a few of the questions which we have been exploring options on. And therefore, I would not like anyone to assume that the emphasis being put on ocean-cooling and once-through cooling in this presentation in any way is intended to preclude the value or the future relevance of using fresh water in inland plants.

I think that there are a number of issues that need to be looked at, and I'll talk about this briefly following this presentation.

So, Rick, whenever you're ready. You can go to the second slide. I'm wondering if you may need to take it out of that holder. I didn't realize how much glare it was going to cause, but it looks like it may work better.

(Off-the-record conversations for technical adjustments.)

MR. HOFFMAN: Do the Commissioners have a hard copy of this?

PRESIDING MEMBER LAURIE: Yes.

MR. BUELL: There are hard copies on the table as you come in, if you would like to get a copy.

MR. HOFFMAN: This first slide addresses kind of the energy profile as it relates to the presence of once-through cooling systems in the state now, and is directly responsive to an earlier question of yours, Commissioner Laurie.

About 40 percent of the state's generation is now once-through cooling. About 8 percent of that total is nuclear. And most of those plants, about 20,000 megawatts worth, are intaking and discharging directly on the coast.

There are several plants, about five or six -- close to 5000 or 6000 megawatts which are now being proposed, or in the case of Moss Landing, under construction, utilizing these type of systems.

And with this 20,000 megawatts in the fairly extensive sites with currently existing intake and discharge structures with currently available gas supply and electric transmission structures, transmission systems, the repowering or expansion of capacity on these sites could provide a substantial amount of the future demand for the State of California.

And as you'll see on one of my late slides, that once-through cooling process is extremely efficient relative to other projects. One analysis that we did on a 1000 megawatt project shows that you lose close to 100 megawatts when you go from a once-through cooling system to a dry cooling. Referencing Mr. Chamberlain's earlier remarks.

I would also point out a couple existing state policies of the California Coastal Commission in the Coastal Act now prioritize the value of coastal dependent industry giving some preference and priority to using these existing plants.

The State Water Resource Board policy sets a priority for power plant cooling water uses. And the highest priority is given to ocean water for cooling, next to wastewater which is discharged to the ocean.

Just a quick, this next slide --

COMMISSIONER PERNELL: Can I stop you here before we go to the next slide, --

MR. HOFFMAN: Yes.

COMMISSIONER PERNELL: You indicated that had gone from a wet system or once-through system to a dry cooling, you lose about 100 megawatts of efficiency?

MR. HOFFMAN: On a 1000 megawatt plant.

COMMISSIONER PERNELL: On a 1000. So, we talked earlier about there is water basins, and if we had a situation that's inland with a depleted water basin, the probability of an applicant wanting to site a plant there is, in your opinion, --

MR. HOFFMAN: Very low.

COMMISSIONER PERNELL: -- very low. And it's because of --

MR. HOFFMAN: I think, and I'll talk about that --

COMMISSIONER PERNELL: -- the water issue?

MR. HOFFMAN: -- more later, but, as Joe indicated before, it will have a lot to do with the adjudication existing in that water basin, with the available supply, the cost, the potential for tradeoff with state water, the availability of groundwater, all those issues.

The next slide. Generally these modernized or repowered plants offer a lot of benefits, most of which we presented in the case of Moss Landing; including considerable reduction in the use of sea water because of the 30 to 40 percent increase in efficiency; usually a reduction in the flow, which I'll talk about in a minute; reduction in air emissions; reduction in the use of natural gas which in this market is of extreme importance to the ratepayers, and will have a major effect on the future cost of power supplies in this state.

We have the capability of producing a much quieter plant, covering a much smaller footprint, with reduced marine impacts. And we can avoid a lot of construction impacts typical of a greenfield site.

The smaller profile of these plants, you know, at Morro Bay, for example, we're taking down a plant that's 165 feet high and has three stacks 450 feet tall, and replacing it with a plant which, for the most part, is less than 50 feet tall and has stacks of 145 feet.

There are a couple, the heat recovery steam generators on that plant that approach, I think, 90 feet. But for the most part, that plant's profile is a lot smaller. Particularly an important issue along the coast.

Typically these plants will result in considerable improvement in coastal access and dealing with coastal related environmental issues.

The modern plants also provide -- next slide, Rick -- a number of marine and water biology impacts. One of the examples that we use in a plant that we're proposing before the Commission now results in reduction in annual flows of close to 40 percent; reduction in impingement and entrainment as a result of those reductions in flows.

An annual cooling water flow per kilowatt hour reduction of over 40 percent. And a reduction in temperature of the water decreased and the heat load of almost 40 percent reduction to the receiving waters. And the total heat load reduction on a per kilowatt hour is more than 40 percent.

Next slide, please. As I implied before, the repowering of an existing site preserves and expands the most efficient form of energy production we have today.

I would point out there are people who are raising a lot of questions about the exchange of these new plants, or the use of these new plants in lieu of letting the existing plants run, and I would just point out that in this environment, and it looks for the foreseeable future, Morro Bay for example, the existing plant, it has run more in the last year than it has run in the last 15 years.

And the emissions from that plant, the water demand from the plant are considerably higher than the proposed facility which will increase production of energy in megawatts by about 20 percent.

So, the reuse of existing sites and replacing existing plants is a major positive environmental effect. And I think that one could go so far as to call it a demand side management tool in the sense that you're using the fuel far more efficiently than you would be otherwise.

These plants, the use of them results, as I mentioned, in decreased coastal environmental impacts. If we can avoid using cooling towers on the coast I think that's very important from a visual standpoint because of the size and the unsightliness of cooling towers. Not to say that there aren't appropriate places for them. And the noise associated with these, as I mentioned before, is also a factor.

Next slide. The counsel for the State Water Board, Craig Wilson, spoke briefly to the issue of what is happening at the state level with respect to existing versus new discharges, and how this might be handled.

This is an extremely important issue to those generators in the State of California who are looking at repowering of these existing sites.

And I would just point out that from the two regulatory issues which drive the water issues at a coastal plant using once-through cooling are federal regulations which were referenced by Mr. Anton and Mr. Wilson.

These are called section 316(a) which has to do with the thermal discharge of a power plant, and section 316(b). And I will talk about those a little bit here.

This slide references the issue of existing versus new discharge. And although Mr. Anton pointed out that it's difficult to evaluate in the short term the thermal effects of a power plant, I would argue, and will make the point here, that most of these plants have extensive data available about both the thermal discharge and the effects of the intakes. Some less thorough than others, but there is information out there.

And we believe, particularly on the thermal side, short-term studies in the range of 60 to 90 days, in some cases, doing thermal overflights and temperature recorders in the water, can enable a developer to come up with an extremely accurate profile using mathematical modeling of what is going to be happening with the plume, the thermal plume, and what the predicted biological effects might be of that discharge based on historical knowledge and the technology that we have today to predict what will happen with this thermal discharge.

So, the issue that we're facing today, and reference was made to the federal regulations, I'd like to address that briefly, although it's not in my presentation.

We have submitted over 300 pages of comments through a group called the Utility Water Action Group in Washington, D.C. on these federal 316(b) regs. And our strong position with that proposed set of regs for EPA, which is currently on new facilities, is that a facility being repowered on an existing site in California does not constitute a new facility.

And that we can use the existing discharge and intake systems without major modification, and thereby qualify as an existing facility, and thereby, under the 316(a) regulation, enable us to operate under the approach which Mr. Wilson described before, of meeting the requirements, we call them the BIC requirements, the requirements that a balanced, indigenous community of the populations of the fish and shellfish, et cetera, be maintained in that biological environment.

This is --

PRESIDING MEMBER LAURIE: Mr. Hoffman, in your papers that you're referring to, what are you using as a definition of repower?

MR. HOFFMAN: Well, probably the term modernize would be a better term. This might vary from case to case, but it would certainly, for example, in the case of Moss Landing it involved the replacement of 600 megawatts that had been shut down previously by PG&E, and the installation of over 1000 megawatts which then operate in conjunction with the existing operating 1500 megawatt plant, which is there now.

PRESIDING MEMBER LAURIE: So you, in your papers you have not defined the term repower or to modernize?

MR. HOFFMAN: Other than to say that it involves the reuse of existing discharge and intake facilities at an existing power plant site.

In Morro Bay we're going to take down the entire old plant and replace it and use the existing discharge and intake facility.

COMMISSIONER PERNELL: If you take down an old facility and construct a new one, as long as you're using, in your scenario, as long as you're using the intake and discharge apparatus for the plant, you're categorizing that as repowering?

MR. HOFFMAN: That's correct.

COMMISSIONER PERNELL: Even though you got a new facility?

MR. HOFFMAN: I don't know that the term repowering has particular legal meaning in this context, so -- I think that the term of significance in the federal regs is is it a new facility or an existing facility.

And there are definitions in the Clean Water Act which relate to that, and which need to be complied with. And since I'm not a lawyer, I can't give you a clear explanation of that.

But we're using the term repowering and modernization somewhat interchangeably here.

COMMISSIONER PERNELL: Right, but -- well, please continue.

MR. HOFFMAN: Okay. I would point out one thing about the thermal regulations under

316(a). If you are defined as a new discharge, the challenge, and I think the issue that we all might face in terms of how can we expedite power plant development and protect the environment, is that the new discharge requirements are that you meet a 20 degree temperature difference between your intake and your discharge -- I'm sorry, between the discharge and the receiving waters, where you're discharging.

You also have a requirement to meet, in the ocean, anyway, a four degree difference between your discharge and the receiving water at 1000 feet.

These parameters are somewhat arbitrary. In fact, in discussions with a Regional Water Board member recently, I was told the four degree figure was arrived at not based on any scientific studies which indicated that this parameter was one which protected species, but that it was, in fact, the lowest temperature they could measure and make the differential.

So, the point here is you can get tangled up in long-term studies of highly detailed nature trying to demonstrate these distinctions when, in fact, under the existing discharge definition you have to meet the same marine biological protective parameter of protecting the balanced indigenous communities. And then you don't get tangled up in that. And I think that's an important point.

We would also argue that these replacement plants can usually meet the requirement that there be no adverse material change in the discharge in order to qualify for this existing discharge classification.

Morro Bay is a good example. We'll be lowering the temperature, lowering the overall heat load over time, and we'll be lowering not only the intake volume going through the plant, but we will significantly slow the down the velocity of water coming into that plant, and thereby reduce the number of species of fish that are caught on the traveling screens that screen out anything coming into the plant.

PRESIDING MEMBER LAURIE: I think we're going to start getting some dirty looks from our general counsel if we continue to make reference to existing projects.

(Laughter.)

PRESIDING MEMBER LAURIE: So, attempt to

speak as generically as we possibly can.

MR. HOFFMAN: Okay. I forgot that admonition prior to this. Thank you for the reminder.

On the next slide, Rick, we'll talk briefly about the 316(b) process which regulates the intake. I would point out that the federal regulations are already set up to expedite the process. And by this I mean that the CEC has what seems to be, based on our experience of working with the staff and the regional water boards, a very effective memorandum of understanding for working together.

And that the driving force behind these water analyses is the NPDES permit process under the Clean Water Act, which is handled by the regional water board.

I think the processes we've worked in the past have worked pretty well. I think we're all looking for ways to help streamline those. We believe that if we can present adequate information up front, and that we can demonstrate that we're not increasing impacts from what one might reasonably assume to be a baseline of an existing plant, and in this condition I would, you know, maybe make a distinction between different facilities without mentioning names.

But that there are facilities where there's clearly a case if a plant's being taken down or being taken out of use, that there's an established baseline from that plant's operation. And that the new plant will then be compared against that.

There may be situations where if the old plant continues to operate one would look at it slightly differently.

I would point out that the existing plants using once-through cooling water systems have, as I mentioned before, extensive studies that can often be confirmed in a reasonably short period of time.

And we would recommend both that extensive reliance be made on these studies, and that up front it be determined what is necessary to be done in order to, you know, achieve a confirmation that might have been determined in a previous NPDES permit that a) the facility is in compliance with the BIC requirements of beneficial indigenous species protection; and also that it meet what they call BTA, or best technology available, for minimizing adverse environmental effects from the intake from impingement and entrainment.

PRESIDING MEMBER LAURIE: From a developer's perspective, is it your view that the federal requirements, as set forth in 316(a) and (b), with proper engineering, can be met?

MR. HOFFMAN: Yes.

PRESIDING MEMBER LAURIE: Thank you.

MR. HOFFMAN: I think we are somewhat concerned about the new proposed regs, however, because they, as counsel mentioned, could cause some fairly severe changes in the process.

PRESIDING MEMBER LAURIE: Thank you.

COMMISSIONER PERNELL: Just from a regulatory standpoint, the California Coastal Commission is an entity that you would have to go through in order to construct a plant on the California coast?

MR. HOFFMAN: Would you rather answer that, Joe?

MR. O'HAGAN: No, I'll defer to you.

(Laughter.)

MR. HOFFMAN: The California Coastal Commission, under the Coastal Act, has the authority to determine whether or not a project, at least this is my understanding, is consistent with the Coastal Act.

It will make recommendations through the Warren Alquist Act process that the Energy Commission uses, and in general its determinations or assumptions are required to be followed by the Energy Commission.

There may be conditions under which the Energy Commission determines that a Coastal Commission proposal is either infeasible or less environmentally sound than what they, or in this case, perhaps, the water board is proposing. And they may therefore stay with their own approach.

COMMISSIONER PERNELL: Right. And then there's a federal requirement that you have to adhere to, as well, which is what we're talking about here, the 316 --

MR. HOFFMAN: Yeah, this 316(a) and (b) are implemented by the Regional Water Board, and with certain circumstances that counsel mentioned before, where there's an exception being requested to the thermal side of it going up to the State Board for concurrence.

But, as far as 316(a) and (b) are

concerned specifically, it's my understanding that's not the responsibility of the Coastal Commission.

The Coastal Commission has its own regulations and interpretations as it relates to water quality. And it will impose those.

COMMISSIONER PERNELL: Right. I guess what I'm not understanding is what role does the federal government play in --

MR. HOFFMAN: Oh, I'm sorry. The federal government has, as I understand it, chosen similar to EPA on the Clean Air Act, delegate it down to the regional water boards through the State Water Board, the authority to implement 316(a) and (b).

COMMISSIONER PERNELL: Thank you.

MR. HOFFMAN: Next slide. I think that we've covered this adequately. So let's go to the next slide.

Well, this one I'll explain to you briefly by taking out all the yeses and noes and putting little checkmarks in there, makes it a little bit easier.

Across the top line, this is a comparison of cooling system advantages and disadvantages compared to once-through cooling.

On the top left is the harbor intake ocean discharge. And across the top there are the categories that increase marine impacts, increased air emissions, increased visual, noise, land use, construction, capital cost and efficiency.

And if you were to put in an ocean intake in a cooling system you would have a lot more increased impacts for a variety of reasons, which I won't go into.

Similar on an ocean discharge. You would have increased land use effects, construction impacts, capital costs and efficiency hits.

If you use cooling ponds, the third from the bottom there, as part of the cooling system you have considerably higher impacts, as you do with cooling towers. And I think from the Commission's experience with inland plants using fresh water and cooling towers, you're aware of the PM10 emission issues associated with those. They obviously cause a greater visual impact and there is some noise associated with them. They take up more land and they have greater construction impacts.

The air cooling is of a similar nature, although the emissions don't increase. You have tremendous efficiency hits. And a number of other direct effects.

Next slide. This next slide shows the comparison from an efficiency standpoint. The next two. And I'll explain this.

The once-through cooling, if it were considered the standard, in comparison, and this is for a 1000 megawatt plant, a natural draft cooling tower which one might think of a nuclear, the big concrete towers as an example of that. You would lose about 48 megawatts on a 1000 megawatt plant in efficiency.

And a mechanical draft cooling tower, typical of many of the inland plants being built with fresh water, you have about a 5 percent loss, or 50 megawatts on 1000. And on an air cooled system, up to 100 megawatts.

And as it's mentioned at the bottom of the slide, the reduced efficiency will be replaced by other generating units which will be in general, until the entire, you know, fleet in California is replaced, more expensive and higher polluting.

PRESIDING MEMBER LAURIE: And would you agree that efficiency is one of many factors that we need to examine? For example, when you look at these four alternatives, they might all look different in physical appearance, so that depending upon the community you're in what it looks like may make a difference.

Water availability in the geographical area may make a difference. Cost of water in a geographical area may make a difference.

So, if I were to write down that efficiency is an important, but only one of the criteria that needs to be examined, when you're looking at which alternative to utilize, would you agree with that statement or not?

MR. HOFFMAN: No, I would agree with that. I think there are obviously situations where different systems are more appropriate, even given the efficiency hit.

I think we're, you know, given that we've got gas prices today that are several times what they were a year ago, we're a lot more sensitive to this.

PRESIDING MEMBER LAURIE: Can you go into cost differentials? Are you going to talk about --

MR. HOFFMAN: Yes, let's take a look at the next slide. That's exactly what that is. And unfortunately, like everything else we're looking at today, it's going to be hard to read.

But the numbers on the left, since you can't read them, the lowest one is 100 million, 200 million, 300, it goes in hundred-million-dollar increments.

The blue bar on the chart shows the difference, comparing over 30 years of operation, the cost of mechanical cooling, natural draft cooling, and air cooling with different gas prices.

So the blue bar shows that with a mechanical cooling, which is a fairly typical multi-tower fresh water cooling system, you're hit on the power plant cost of producing power over 30 years would be about $130 million. With gas at $3.50 an mmBtu at about --

PRESIDING MEMBER LAURIE: Is this again for a 1000 megawatt plant?

MR. HOFFMAN: This is for a 1000 megawatt, yeah. And for $5 mmBtu gas, which is probably where gas will settle back into, somewhere in that range, perhaps a little less, you have about a $200 million hit.

And then you go over to the right and you see the air cooled, where over the cost of -- over a 30 year term there's almost a half-billion-dollar increase in the cost of that power over 30 years, with a $5 mmBtu cost.

Now that cost would triple to a billion-and-a-half dollars at today's prices. Now, nobody expects to see gas stay at today's prices, but just as an indicator.

COMMISSIONER PERNELL: This chart doesn't reflect the construction costs of the plant, just the operation and maintenance costs?

MR. HOFFMAN: Quite right, and it also doesn't connect the O&M -- doesn't incorporate either the O&M costs or the increased construction costs.

PRESIDING MEMBER LAURIE: If I were to be crass, and I'm only saying this because Mr. Tomashefsky to my left asked me to ask this question, otherwise I certainly --

(Laughter.)

PRESIDING MEMBER LAURIE: Let's say, as regulators, we could care less how much your operation is, except to the extent that it affects the consumer, and the price that the consumer pays for your product.

So are you able to -- or what would we have to do to use the data in this slide to figure out what the cost to the consumer would be, or the additional increased costs of the various systems?

Are we able to do that by manipulating numbers?

MR. HOFFMAN: Yeah, well, yeah, we could do it fairly easily, although my mathematical mind is not capable of doing it right here. We could figure out fairly reasonably the total megawatt hours produced over the life of this plant, and come up with a cost per kilowatt hour pretty easily. And we'll be glad to provide those numbers to the Commission.

PRESIDING MEMBER LAURIE: If you could do that would be very helpful.

MR. HOFFMAN: Yeah, I will make sure I get that to Mr. Buell, and that he gets it forwarded to you.

And we'll also provide in that table some numbers on how O&M and construction costs would factor into it.

COMMISSIONER PERNELL: That would be helpful.

MR. HOFFMAN: The last slide here is just kind of a summary. I think that from the standpoint of water process and evaluating the water factors we are concerned about certainty associated with schedule.

It is very difficult to know whether or not we can meet a year-long or a six-month schedule when we enter it without certainty. So timetables and standards of what we need and how we're going to approach it are very important.

As I mentioned before, focusing on existing studies and data and confirmatory studies are important.

And we would just make a recommendation that when a replacement plant or modernization lowers the water use, reduces biological effects from an existing baseline plan, that this project should be able to move forward without mitigation requirements.

I thank the Commission for this opportunity to present this, and I'd just like to make a couple comments about the fresh water issue, because it was discussed in such detail.

Commissioner Laurie, in response to your question about groundwater adjudication, I'd point out that we're also looking at some opportunities in the inland areas.

And in areas where groundwater is not adjudicated, our understanding is that a general rule of thumb, or rule of law, is that a landowner can draw groundwater to the extent that he's not impacting on his neighbor's supply. And this is sort of a common law approach to it.

And there are a number of basins in California where there are pretty substantial groundwater supplies. And I think that these areas where there is not adjudication, and one of the reasons there isn't is these farmers who are there prefer to avoid it at all costs.

And I think the solution to the fresh water problem may lie in, and this will remain to be seen as we move forward with proposals, in a creative process that involves the agriculture community, that attempts to balance the use of groundwater with such approaches as water banking, recharging the aquifer, a tradeoff of groundwater with water project water, and a number of creative approaches that in the end will have agricultural benefits in that, in some cases, the farmers can use less water-demanding crops, they can improve the quality and protection of the land from salting-up, from high use of fertilizer and irrigation over time.

It can provide the farmers with income. It can provide opportunities for lower cost power. I think that was a very interesting chart that the gentlemen from DWR put up showing the considerable cost to some farmers for the cost of pumping. It can be 30, 40 percent of the cost of the water, to pump, just for the electricity.

So I would just point those things out. And, also, I don't think very much emphasis was put on this, but we believe strongly that you can virtually eliminate the discharge issue associated with these cooling towers and inland water plants through zero liquid discharge systems, which a) enable you to considerably increase the efficiency and the use of water in a power plant; and result in no discharge and no Aaron Brockovich problems. And, you know, we all like to stay away from those. And not have to use filtration ponds.

The solid discharges are generally nontoxic and can be disposed of in a reasonable manner.

COMMISSIONER PERNELL: Is that a fairly new technology, or has that been around?

MR. HOFFMAN: I think that it isn't real new, but the creation of these systems at a cost effective level is somewhat new. And I think that there are systems out there now which can be reasonably incorporated.

One of the challenges is finding water which has a quality which doesn't cost a fortune to build the system for it, and removing, for example, suspended solids. But they are definitely available.

In fact, if I'm not mistaken, one of the plants that has been approved already uses this system, in southern California.

MR. O'HAGAN: Several of our projects have been certified to use zero discharge, and with a drop in cost of like reverse osmosis and alternate filtration and things like that. It's turned out to be a lot more cost effective technology to use than it was 10, 15 years ago, though it was available then.

MR. HOFFMAN: Thank you for the opportunity. That's all I have.

COMMISSIONER PERNELL: Well, thank you for your presentation. It was very informative.

PRESIDING MEMBER LAURIE: On the question of groundwater, again, when you all are looking for potential sites, the benefit of finding an adjudicated basin is that you know what the rules are going to be. And either you're allowed or either you're not allowed.

But if you're out in the more rural areas of the state where perhaps there is not adjudication, and let's say it's agricultural, and you propose to take a 30-acre parcel that's currently utilized for agriculture, and utilize it for power plant purposes, I think the water use is greater for the power plant than it would be for 30 acres of agriculture, right?

MR. HOFFMAN: Obviously, yes; considerably greater.

PRESIDING MEMBER LAURIE: Do you stay away from those circumstances because of the potential of litigation over the use of those basins, or do you at least check it out to see if there's going to be some kind of deal that you can work? Or do you just remove those from your list of possibilities?

MR. HOFFMAN: Well, it's a very complex answer, but I'll use an example in another state to respond to it. Where in a desert situation we literally purchased thousands of acres to secure a water right for a power plant and we also restored most of that land that we bought to natural conditions and maintained an open space. That was one way to get the water right.

We would be less likely to do that in California in an already developed agricultural region because of the increased costs.

But as I alluded to before I would just say that it's going to take some creative effort in working with the agricultural community in trying to find ways to use the power plant presence to a) reduce their costs of production and provide them with benefits; assist them in implementing and I think, hopefully I won't offend anyone, but I think many people in the room are aware that the greatest opportunity for conservation in California may be in the irrigation systems, installing drip irrigation, and the cost of that may be offset by benefits that the farmer might get from working with the power plant developer.

So, that, and you know, being creative about how groundwater is used through recharge, through banking, through exchanges, those are all approaches that are being looked at.

PRESIDING MEMBER LAURIE: Excellent, thank you.

At this time I think we want to go to -- we want to provide an opportunity for questions or comments on panel member comments? Is that what we want to do, Mr. O'Hagan?

MR. O'HAGAN: Yes.

PRESIDING MEMBER LAURIE: I think so. Okay. So, let's provide that opportunity. Ladies and gentlemen, for those of you wishing to comment or ask questions on these specific presentations please feel free to do so at this time.

If not, then we will thank the panelists for your outstanding presentations and we will see you back here at approximately 1:20 for a continuation of the program.

Thank you very much.

(Whereupon, at 12:15 p.m., the workshop was adjourned, to reconvene at 1:20 p.m., this same day.)

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AFTERNOON SESSION

1:23 p.m.

MR. O'HAGAN: Briefly, sort of a recap of this morning's discussion, I think there was a number of issues raised regarding water supply and water regulations in California. As was pointed out there's a diverse number of local, state and federal water regulations that come into play, and there's obviously a lot of options for water supply for power generation.

This afternoon's discussions are going to deal with technological solutions. We have two consultants here that are Mike DiFilippo on my left and John Maulbetsch on my right. They are consultants working for the California Energy Commission right now under the PIER program.

Mike is looking at the use of degraded water and cooling towers. And John is looking at dry cooling.

So, without further adieu. Oh, John's first? I'm sorry.

MR. DiFILIPPO: The agenda says John's first.

(Laughter.)

MR. O'HAGAN: Okay, John's first, my

apologies.

PRESIDING MEMBER LAURIE: 'Afternoon, sir.

DR. MAULBETSCH: Commissioner Laurie, it's good to see you again. The last time you and I were in a room talking about dry cooling was a couple months ago when Det Kroeger was here from South Africa.

PRESIDING MEMBER LAURIE: Correct.

DR. MAULBETSCH: And he gave some general background on the history of dry cooling. And what I'd like to do today is become a little more quantitative and a little bit -- get behind some of the things he said and explain a little bit about why they may be true.

PRESIDING MEMBER LAURIE: Thank you.

DR. MAULBETSCH: The first slide, if we could, Rick. Just to calibrate ourselves, I'm going to be talking largely in terms of the kind of power plants that are currently being considered and being licensed in California right now.

I will be talking largely about 500 megawatt combined cycle plants of which one-third, or perhaps 170 megawatts, is on steam. Now that will make some of the numbers, in terms of economic impact, come out lower than what you heard this morning from our colleagues from Duke, because they were talking about 1000 megawatts all on steam. And it's just a different size.

If you carry around in your head a number like 10 gallons per minute per megawatt --

PRESIDING MEMBER LAURIE: I don't normally do that, but I suppose I could for a brief period.

(Laughter.)

DR. MAULBETSCH: In some bizarre set of circumstances it might even be useful.

PRESIDING MEMBER LAURIE: Yeah, nothing else has worked, so I could try that one.

DR. MAULBETSCH: For the plant that I'm talking about, for the steam side of a combined cycle plant, that works out to about 3000 acrefeet per year of water consumption for the condensation of the steam coming out of the turbine.

There are other water loads at these plants, but they're not very big. There's auxiliary cooling; there's makeup to the steam cycle; there's sometimes injection into the gas turbines; and there's the so-called hotel load, the air conditioning of the buildings and sanitary water and so on, that in round numbers may be something like 5 percent of that 3000 acrefeet.

MR. TOMASHEFSKY: What type of load factor is that?

DR. MAULBETSCH: Beg your pardon?

MR. TOMASHEFSKY: What type of load factor are you assuming with the 3000 acrefeet? Is it running all the time?

DR. MAULBETSCH: I'd probably assumed 100 percent at that point, you know, if it's -- or 85 percent or something like that. These are all, I mean you can see that's to one significant figure.

MR. TOMASHEFSKY: Sorry.

DR. MAULBETSCH: So it's about 3000. The usual method, and we're talking now about these inland combined cycle plants, the usual method of condensing the steam out of the turbine is with a wet cooling tower.

Steam comes out of the turbine into a shell and tube condenser. Cold water is run through the tubes of the condenser; it heats up as the steam condenses; and the hot water is then returned to the top of a cooling tower where it's spread out on a deck at the top.

And it sort of dribbles down through a material called fill or packaging. And at the same time a fan draws air from the surroundings through that fill or packing. The air and the water mix. A small portion, perhaps 1 to 2 percent of the water is evaporated.

The remainder is cooled by perhaps 20 or 25 degrees Fahrenheit and returned to the condenser. That's typical recirculating wet cooling.

PRESIDING MEMBER LAURIE: One to 2 percent, is that what results in the plume?

DR. MAULBETSCH: Yes, yes, under certain circumstances. That evaporated water, as it leave the tower, recondenses in the colder air and shows you a visible plume on some days.

The operative environmental quantity that tells you how much cooling you can get, how cold you can get the water coming off that tower is the so-called wet bulb temperature. Are you familiar with that term, or --

PRESIDING MEMBER LAURIE: No, sir.

DR. MAULBETSCH: Okay, the normal temperature or the dry bulb temperature is the temperature that you measure with a regular thermometer.

If you keep the bulb of that thermometer wet, and air passes over it, some of that wetness will evaporate and cool the bulb. That's why you feel cold even on a warm day at the beach if you're wearing a wet, sweaty t-shirt.

The wet bulb temperature is typically a lot lower than the dry bulb temperature, and so the water that you get off a wet cooling tower can be a lot cooler than the water that you would get off a dry cooling tower.

That's part of the reason, and we'll talk about this more in a couple of minutes, that the efficiency for dry cooling towers, as was stated this morning, is less. You just can't get as cold water off a dry tower as you can off a wet tower.

This shows, if you're not familiar with the equipment, a typical mechanical draft inline cooling tower. You can see a little plume coming off of the one on the left-hand side of the slide. We talked about evaporation of about 10 gallons per minute per megawatt, a blowdown, which my colleague, Mike DiFilippo, will talk about more in the next presentation, at some cycles of concentration is perhaps 10 or 20 percent of that.

Drift, which is the small droplets that sometimes get entrained in the air stream and blown out the top of the tower is negligible from a water consumption standpoint. It's still a few gallons per minute, not per megawatt total. It's a very small quantity of water.

There are other issues besides water consumption with wet cooling. As was stated several times this morning, the blowdown from the tower, the water that you have to discharge from the tower in order to limit the buildup of suspended or dissolved solids that are brought into the tower is an issue.

Drift deposition can be an issue if there's salt in the drift or if it deposits on a road in the winter and ices up. Plume visibility can be an issue if it's in a place like over a freeway where you want to be able to see. And noise can be an issue, as was pointed out.

Now the same story for dry cooling. Here, the steam when it comes off the condenser -- comes off the turbine, is taken out across the property to an air-cooled condenser. The steam is taken directly off of the tower.

It usually goes in on a steam header at the top and is distributed. And as it condenses it flows down those angled tubes which have fins on the outside, and we'll see a picture of it later, so you see what it looks like. Is collected in condensate collectors at the bottom of those tubes, and returned to the power plant for revaporization, reboiling through the steam condenser.

It's analogous, if you like, to an automobile radiator where the stuff you're trying to cool is inside tubes, it's being cooled by air blown over the outside.

As we said a minute ago, what you get in terms of cold water temperature off these is determined by the normal or dry bulb temperature.

This is a picture of a dry cooling tower. I think this is one of the same ones that Detlev showed a couple of months ago. It's a South African tower. You can see the sort of A-frame construction; it's the structure to the left of the buildings.

The water consumption for plants which are dry cooled is not zero. You still have that 5 percent hotel and auxiliary load we talked about. There's no blowdown, there's no drift, there's no plume. Noise is still an issue, and in some cases they may be noisier than a wet cooling tower because you move a lot more air through a dry one than through a wet one.

Okay, there's been a lot of talk about the cost comparison between dry cooling and wet cooling. There are a lot of ways to make that comparison. What this plot in front of you shows is just the capital cost ratio; this is just the cost of the equipment.

For a wet tower it includes the tower plus the condenser plus all the pumps and fans. For a dry tower it includes the tower, the fans, the motors, the steam ducting and so on.

It shows the results from about ten different studies that have been conducted over the years, some of them quite a few years ago. And you see ratios that range from about 1, which would suggest that the capital costs are equal, to nearly 4.

I would say that for most situations the answer is somewhere around 2, between say 1.5 and 2.5, if you compare an optimized wet cooling tower designed to be the best wet cooling tower it can be, with an optimized dry cooling tower.

PRESIDING MEMBER LAURIE: And how does that translate into numbers of dollars? What kind of dollars are we talking about?

DR. MAULBETSCH: Okay, well, let's look at the next slide. These are costs for a dry cooling tower. And it's in dollars per kilowatt. So for 170 megawatt steam side of the plant that we were talking about, you have to multiply those numbers by 170,000.

So where it says $100 per kilowatt, that's a $17 million tower. It's plotted against what they call the initial temperature difference. That's the temperature that you're condensing the steam at minus whatever the temperature of the air outside is at the time.

So, when that number is big, over on the right-hand side, at 50 or 60 degrees Fahrenheit, you can get away, for a fixed load, with a relatively small tower.

If you want the tower to meet design conditions on much hotter days, down where there might be only 20 or 30 degrees different, then you have to have a much bigger tower which costs correspondingly more.

So the cost, depending on how you select the design point, can vary by, on this plot, a factor of 2.5.

The costs of dry cooling with changes in atmospheric conditions are more variable than wet cooling, because the wet cooling, you could construct a similar plot here for wet cooling, I haven't done that, but you could.

But you would plot it against what they call the approach temperature, which is the hot water temperature of the cold water temperature leaving the tower, subtract it from the atmospheric wet bulb temperature.

Wet bulb temperature varies a lot less from cold days in the winter to hot days in the summer than dry bulb temperature does. And so the variation is somewhat less.

However, if you go back to the previous slide, and we don't need to do that necessarily, but if I said that there was typically between optimized dry and optimized wet, perhaps a difference of a factor of two.

So for this 170 megawatt steam side power plant, let's take the point and say 30 degrees, and so we're at about $200 per kilowatt, that's a $34 million tower. Half of that is $17 million. So the difference between the two in capital costs might be $15 to $20 million.

Why do dry cooling towers cost more? Well, there are a number of reasons for that. If you look at the next slide, this is a tube that you would find in a dry cooling tower. It's more expensive to make metal tubes with extended surfaces on the outside than it is to make splash packing that water dribbles down over in a dry cooling tower.

So the surface, itself, where the heat transfer takes place, is more costly. In a wet tower you also have to pay for a condenser, but even the combination is more costly for dry.

You have to move a lot more air to cool dry than you do wet. So, more fans and more motors are required, and that's a significant portion of the cost of the tower.

And the configuration we talked about, you have to bring the steam from the turbine hall out to where the tower is. Steam at that pressure is not very dense, and so you have to move a lot of volume of steam. So these tubes are very large. And you can see those two white lines going along the top of the dry cooling tower represent the steam ducting, and that's a significant cost to purchase and to support.

Okay, now let's assume we have chosen a dry cooling tower and we've asked that it meet turbine design conditions at say a 65 degree ambient day, or a 75 degree ambient day.

And then the summer comes along and it gets hotter out there. As the temperature goes up for three different turbines that I've selected here from 65 or 75 up to 100 or higher, the so-called back pressure on the turbines, the pressure at the back of the steam turbine that the steam is exhausting out to, goes from 2.5 or 3.5 inches of mercury, which is a pretty high vacuum, up to 6 or 8 or 10 inches of mercury.

When that happens the turbine performs less efficiently. And on the next plot you see a plot of turbine back pressure which we just said goes from 2.5 or 3.5 at design up to 6, 8 or 10. When that happens the efficiency goes down and heat rate ratio -- heat rate is defined as the amount of energy that you have to put into the plant, divided by the amount of energy you get out of it as electricity.

And this has been normalized to the design point, so at 1 that's the plant operating at normal design conditions and a back pressure of say 2.5. Gets hot out, temperature goes up, the back pressure goes up to 8 or 10. The heat rate ratio is 1.1.

Well, that corresponds pretty closely to what Wayne Hoffman said this morning about a 10 percent reduction in output, of going from -- he was talking about once-through cooling versus dry cooling, but the dry cooling tower goes up there, it's about -- I have no quarrel with his estimate of perhaps a 10 percent reduction.

How much is that penalty worth? Well, here we get into stuff that I guess is something you deal with a whole lot more than I do. If you lose 10 megawatts, let's say, from the output of the turbine, which would be, say, a 5 or 6 percent reduction in output on this 170 megawatt steam section that we're talking about, and that lasts for a few hundred hours a year when the temperature outside is hot enough so that you suffer that kind of a loss.

How much it costs you depends on how

much power is worth. I don't know how much power is worth. I don't even know how much it costs anymore.

(Laughter.)

DR. MAULBETSCH: But I picked some numbers ranging from $55 a megawatt hour which is one that we read in the paper a lot, up to $250 a megawatt hour. And so if this 10 megawatt loss lasts for say 400 hours, that can cost you, on this 170 megawatt plant, somewhere between a few hundred thousand and a million dollars.

If power's worth $750 a megawatt hour, you know, you can do the arithmetic as well as I. It can get very costly, as was pointed out.

Now, what could you do about that? One thing you can do, I think this was also mentioned by someone this morning, if you have a little bit of water available you can use a little bit of water at the time of the year when the hot weather is really hurting you. And then go dry during the rest of the year. And you may use water at a pretty high rate during the times that you need it, but averaged over the year you use substantially less.

There are so-called hybrid wet/dry

systems. You were asking about the plume before. Most of the ones that are out there around the country and around the world are not so much for water conservation as they are for plume abatement.

If you have a plume on a cold day and you don't want it, you can heat the plume up a little bit and you can heat the discharge air coming off the wet tower a little bit and the plume will go away.

Another thing you can do, and this is taking a book from the gas turbine people, gas turbines also suffer a capacity reduction on hot days, because they suck in a certain volume of air. And as the air heats up, that means you get less massive air for the same volume. So the capacity of the turbine goes down.

What they do is to spray finely atomized water in the gas turbine inlet. That water evaporates, cools the air, and it recovers some of the megawatts for you. One could consider doing the same thing for a dry cooling tower. But the remaining slides, which we can go through very quickly, just show some of the alternatives for these hybrid systems.

The first one is a single tower design where you have essentially a wet tower on the bottom, a dry tower on the top and louvers to direct the air to whichever one you want or to some fraction of the air to whichever one you want.

This is the usual plume abatement design, because the size wet tower that you can put on top -- I'm sorry, the size dry tower that you can put on top of a wet tower is pretty small compared to the size dry tower you would need to carry the whole condensing load.

PRESIDING MEMBER LAURIE: And these are available now?

DR. MAULBETSCH: These are available now, yes. From at least one supplier, and perhaps it -- at least two suppliers and perhaps three.

The next is a split steam design where you essentially have two parallel cooling systems, a wet cooling tower on one side of the plant, with its condenser, and a dry cooling tower on the other side of the plant.

And you have a steam duct that takes some of the steam to the condenser and some of the steam to the dry cooling tower.

Well, that will work, but if you build both of them full size, you're dealing with a substantially increased capital cost. You have to pay the full price for both towers. That's not a system that I am aware is in place anywhere, at least at full size.

PRESIDING MEMBER LAURIE: To your knowledge when you talk about hybrid system availability, are the systems readily available on the market? Is there a delay?

And if, for example, a developer doesn't know until a project is certified what kind of cooling system they require, and therefore cannot place an order until day 365, do you have any idea about --

DR. MAULBETSCH: I don't know the answer to that, sir. I don't think the cooling tower vendors are terribly backed up right now. But I don't know that to be true. I can find out and I'll let Joe and Matt know, and they can pass the information back to you.

PRESIDING MEMBER LAURIE: Does Duke know? Do you guys know?

MR. HOFFMAN: Wayne Hoffman with Duke Energy. I'm not sure what the lead time is on these, except that on the dry cooling systems there tends to be a considerably longer lead time, as this gentleman, I'm sure, would agree, because of the more complicated design nature.

Generally, a cooling tower system is pretty low tech, often made out of treated lumber in large part. So, those can be designed and built readily.

I would point out, though, that combining these two systems can be extremely costly. And is not being looked at by developers for that reason.

PRESIDING MEMBER LAURIE: Okay, thank you, Wayne.

DR. MAULBETSCH: A third option is I guess what's often called a swamp cooler, where you simply precool the air going in with something that looks like a conventional wet tower. But that water that's going around in the wet tower is just recirculated from bottom up to the top. And serves really only to cool the inlet air, not the condensed steam directly.

The next slide, this is an example of the inlet gas turbine cooling racks that I was talking about. And what they do in front of the air intake is just put up racks with a bunch of little nozzles; spray high pressure water through the nozzles; make a mist and it cools the air.

As I say, you could consider doing that in dry cooling systems. And I think it's a system that deserves being looked at. A lot more air goes through a wet cooling tower -- or goes through a dry cooling tower than through a gas turbine.

And so you would have different design parameters to deal with. But the thermodynamics is straightforward. If you evaporate water in the inlet air you'll cool it down and that will help.

There was a study of this done by a student of Kroeger's a couple years ago, and this doesn't refer to any particular plant, this is just arithmetic basically. But, it shows here, for example, that for a 235 megawatt unit, which they chose as their basecase to look at, as the temperature rose from about the mid 50s up to 90 or above, it represented a 10 or 12 megawatt decrease in capacity.

If you precooled the air to 70 percent relative humidity, which I think amounted to about a 10 or 15 degree reduction in temperature, you recovered most of that loss in capacity. Instead of losing 10 to 12 megawatts, you lost 3 to 5 megawatts.

And the rate at which you were using water during the period you were using it was about one-quarter of the rate that you would use the water if you were cooling the whole thing with a wet cooling tower.

And the capital cost increase for this kind of a precooling spray arrangement is certainly minimal compared to the hybrid tower or the split steam section, which, as Wayne pointed out, can be quite costly.

So, finally, I guess I would leave you with one which you already knew, that water saving cooling technologies exist. Their costs are higher than conventional wet cooling technology, except in maybe some very special circumstances. Capital costs are higher and the plant output is reduced due to some operating penalties of lost capacity or efficiency.

But adding a small amount of water to dry cooling systems can reduce those inefficiencies. It can be done in a way, I think, that does not increase the capital cost tremendously above what you already have to pay for dry cooling.

And so you can help yourself by using a little bit of water, as opposed to trying to use none at all.

PRESIDING MEMBER LAURIE: But the lesson learned and the fact is that when you get into southern California, the further off the coast you get the hotter it is, and less water availability you have.

That's not fair.

(Laughter.)

PRESIDING MEMBER LAURIE: Because it's inconsistent with what our need is. And it's inconsistent with the inefficiencies of the needed technology that is currently available. So the question is what is your awareness of current research being done to increase the efficiencies of dry cooling?

DR. MAULBETSCH: There is work being done on the heat exchanger surfaces; that tube that I showed you a few slides back, which was a round tube with round fins on it. They are getting more effective towers at lower costs by using tubes that aren't round, but are long and almost rectangular with rounded ends and special fins mounted on those.

It was always recognized that those would give you less fan power for more effective heating, but round tubes are easy to make and these aren't. And so they've been working on the manufacturing techniques. And that seems to be working.

MR. O'HAGAN: I just wanted to point out that staff is proposing a tailored collaborative with Mr. Maulbetsch through EPRI under the PIER program to evaluate the spray enhancement for dry cooling facilities. You'll probably be seeing that in a different capacity.

PRESIDING MEMBER LAURIE: I anticipate so. Thank you, sir.

MR. O'HAGAN: Our next speaker is Michael D. Filippo, and he's going to be talking about degraded water use for power plant cooling.

MR. DiFILIPPO: I want to show you some overheads. Now, you should have a copy of this up there. I pulled some of the overheads out. You don't?

Some of the overheads I'm going to show, some of the material that's in the handout is not in the overheads, because I pulled them out. They're kind of simplistic. I'm just going to jump over those.

Like Joe said, I'm here to talk about degraded water for power plant cooling. And why don't we just go to the next overhead.

This is the cooling tower that John talked about. Basically water, regardless if it's fresh water or degraded water, enters the cooling tower and it's used for cooling.

You get a significant amount of evaporation. I deal in gallons per minute. You get about 1700 gallons a minute of evaporation for this size power plant, about a third of it using steam power and cooling for condensing steam.

A cooling tower is designed so you maintain a constant volume of cooling water, and that's done with -- you have water evaporating; you have dry air, relatively dry air going into the tower. It humidifies basically with cooling water, some of the water evaporates, pulls a lot of heat out, about 1000 Btus per pound of water evaporated. That's your cooling, your heat rejection.

Now, to compensate for that -- makeup

for that volume loss, you add what is known as a makeup stream, which is your fresh water or degraded water, whatever water source you have.

As the water's evaporating it's concentrating at the same time. And if you didn't bleed that salt out, in other words you've got so much fresh water coming in that contains natural background salts. If you did not bleed those salts out they'd stay in the tower, because they don't leave in the evaporation, and the concentration of salts would increase very dramatically.

So, there's a bleed stream called blowdown. And this is a practical stream. It's used to control salt concentrations in the tower. And this stream generates water quality, water concentrations and a ratio known as cycles of concentration.

And if we can flip to the next one, which is about two pages back for you guys, it's another cooling tower. It shows flow rates here. Now, what this tower's showing is 10 cycles of concentration. And what that means is that we've pulled enough of a bleedstream off to get ten cycles of concentration in the cooling tower.

Now, cycles of concentration, the higher the cycles of concentration the less the blowdown you have, the less salt you're taking out of the tower. The less salt you have to take out of the tower, the smaller the blowdown stream, the smaller the wastewater stream you have to contend with, especially for an inland plant.

Inland plants, and it was said this morning, try to achieve as high cycles of concentration as possible. Now, with fresh water, especially in some areas fresh water can allow you to go up to 15, 20 cycles of concentration.

Degraded water, and I've showed Joe many examples of degraded water where you're lucky if you can get five cycles, six cycles, seven cycles of concentration.

Let's go to the next overhead, next page. These are just graphical relationships. As you can see, when you get to five cycles of concentration, four and a half to five cycles of concentration, the makeup demand for water kind of starts to level off. That's the top graph.

When you go down -- the graph below just shows you just the blowdown stream component. The red line of the top graph is blowdown. The top line is makeup.

So a lot of coastal plants that have cooling towers operate at 4.5 to 5 cycles of concentration. Number one, they can discharge their water usually to a receiving body. And number two, the cycles of concentration are lower, the water quality -- the concentrations of salts in the water that create corrosion, that create what is known as hardness, scaling, which covers heat transfer surfaces, reduces the efficiency of the overall power cycle, those are reduced when you can operate at lower cycles of concentration, lower salt concentrations.

So in coastal plants you'll typically see five cycles of concentration, maybe seven or eight. And there's no need to go higher, because you have a receiving body of water.

In the inland plants you have to go as high as you can because every gallon water, especially in -- most inland plants are zero discharge plants. They either have to go to an evaporation pond, a receiving body that will take this water and keep it away from groundwater. Or put in some fairly sophisticated equipment to evaporate either to reduce the volume significantly or to just take it away completely.

But let's go to the next slide I'll show you. Now, before I go any further with equipment, let's just look at some degraded water sources.

I've just completed some work in this area for the Commission and there are a whole series of degraded water sources in California. There's contaminated groundwater, and that's just groundwater that's contaminated by something. It could be solvents, it could be heavy metals. It's typically drinking water supplies that are impacted.

There are brackish surface waters and brackish groundwaters. The central valley has got a significant number of salt sinks where you have brackish groundwater.

You have agricultural water which is in some areas a fairly significant volume of water. It's somewhat seasonable, but fairly significant volume of water.

And then in the coastal areas you've got reclaimed municipal effluent in large quantities.

PRESIDING MEMBER LAURIE: Do we care what's in the water? And, if so, why? Is it because of the evaporative portion of it?

MR. DiFILIPPO: Yeah, that's the next page. Why don't we turn to the next page.

The first one, common minerals. This is what's typically in all waters. Tap water's got common minerals. It's just hardness and alkalinity and sulfate and silica and chlorides. These are natural background minerals.

Reclaimed water, in addition to that, which it's usually a little more salty. It has BOD, COD, these are organic compounds. Very low levels. THM precursors. Now, these are chemicals that are generated in the cooling tower when you chlorinate the water for disinfection, you get CHMs. They're known as -- they're precursors to, they are carcinogenic compounds. They're very hard to control.

There's also ammonia and phosphate. And those two compounds, alone, create big problems with cooling systems. And I'll get into that in a second.

You also get hazardous contaminants, depending on the water you could have heavy metals, volatile organic compounds or VOCs, non-VOCs but they're still organic compounds. You could have pesticides.

And then there's other chemical constituents. For chlorate -- MTBE is not up there, but that's obviously another one. You could have nitrates which at very high levels can create problems with pregnant women, for instance. And then there's sulfides and fluorides.

So, there's a whole variety of things that can be in contaminated water or degraded water. And these are just various components of it.

Now, if we can turn to the next one, you know what I want to do, let's go to the one after that and then I'll come back to that one.

Okay. When you've got degraded water, you know, there's different things you can do with it to use it for cooling towers. You just can't put the water in the cooling tower without treating it.

And depending on what the contaminants are, you're going to have to treat it, in some cases for contaminated groundwater before you can put groundwater that has volatile organic compounds in it, into a cooling tower which will strip them right out. You've got to pretreat to get those materials out of the tower.

There's some general minerals that you have to remove from the water before you put them in the tower, depending on what their concentrations are. And that's --

PRESIDING MEMBER LAURIE: Can you do that all on site?

MR. DiFILIPPO: Oh, yeah. And interestingly enough, these technologies are all commercial available technologies. There's not a lot of R&D stuff here, relatively speaking. They're all commercially available technologies. Softening, adjusting pH, reducing silica, removing total dissolved solids, which is TDS, these are all commercially available technologies. They just cost money and they use chemicals, and in some cases, power.

In some cases the water has so many constituents in it of concern, when I say concern, that are of concern to the cooling tower, that you have to actually use -- you utilize side stream softening, which basically takes a portion of the hot water coming back from the condenser, and you soften that, or you treat it somehow and return that to the tower.

In inland plants you may have to go all

the way to post-treatment, and that's where you basically take the blowdown from the cooling tower and reduce its volume so you can put it in a small evaporation pond. Or reduce it to dryness, that's another alterative for cooling towers. And there are some power projects that are utilizing this technology, which has been around since the early '70s, evaporation for these purposes. Used in power plants since the early '70s.

A lot of zero discharge plants built in 1975, 1978, utilize this type of technology today.

Let's go back to the one I skipped over. Now, every time, generally speaking, when you increase the cycles of concentration, in other words try to reduce the volume of wastewater, things happen.

When you increase the cycles of concentration the salt concentration in the cooling tower increases dramatically. So you have the condenser that where all the condensation happens for the steam turbine, the metallurgy may have to go from what is a brass metallurgy to a copper/nickel metallurgy.

And if you really want to increase the concentrations even further, you may have to go to titanium. And these all cost more money, significantly more money to build.

When you increase the cycles of concentration your costs go up, your chemical costs. There are specialty chemicals that are added to the tower to help prevent scale formation, biological formation, sedimentation happening in low flow areas.

So these are all costs that are involved with increasing cycles of concentration. And interestingly enough, whether it's fresh water or degraded water, the higher the cycles of concentration the more chemicals you'll spend.

Degraded water you'll spend more because it's harder to get the higher cycles of concentration anyway. You probably have to treat for that.

Let's go, I guess we're going to have to skip two, get to the next one. There we go. Now, this one here, what this one shows is the same levels of treatment, pretreatment, side stream treatment, post treatment.

Now, with inland plants you've got to go all the way to post treatment, because what are you going to do with all this blowdown? Okay, you're going to try and get the cycles as high as you can and you're going to have to do post treatment, which typically is volume reduction and storage on site of the reduced volume of water, or basically salt.

Alternatively, with coastal plants you may have to do pretreatment, you may have to do side stream treatment, depending on the water and its quality and the constituency, the chemicals that are found in the water.

So, there's a big difference between the two. And inland plants are really distinguished because they have this waste stream they have to handle, in some cases, dryness.

Let's go to the next one here. Okay. I want to talk about post treatment disposal options. There really are three kinds -- there's three levels of treatment.

There are plants out there in the desert that just have evaporation ponds. They're huge, 150 acres, 200 acres of ponds. I personally designed two plants that had huge evaporation ponds. They don't build them like that much anymore. These were all built in the '70s.

You can reduce the volume of waste with

what is known as a brine concentrator or an evaporator. And what it does is it uses an evaporation technology to evaporate the water down to about 10 percent of its original volume.

So if you start with 100 gallons a minute, you end up with ten gallons a minute of waste stuff. And this stuff is pretty yucky looking. A lot of salts in it. It's very thick and heavy.

And then you get this water that the distillate is high quality water that can go back to the plant. You can actually take a credit for it, because it's high quality water.

The waste, if you just had a brine concentrator, you'd have to go to a smaller evaporation pond. And just store it in there.

And then the last, of course, is a brine concentrator with a crystallizer. And what a crystallizer does is it takes that reduced volume of waste and brings it to dryness. And these crystallizers are becoming more popular now.

I was involved in a crystallizer design in 1980. It was huge. It was an electric one. And we spent -- it was a very inefficient system. The ones today are more efficient. And I've got some slides I'll show you of how these combined to get -- as a matter of fact, why don't we go to the next one.

This is just an evaporation pond. Now, in the central valley you'll get about for every gallon a minute of wastewater you have, you need about a half an acre of an evaporation pond in the central valley.

In the desert you only --

PRESIDING MEMBER LAURIE: I'm sorry, give me that number again.

MR. DiFILIPPO: For every gallon per minute of wastewater you need half an acre of pond. In the high desert, like in Blythe, for instance, a third of an acre is kind of the rough number.

So, these evaporation ponds can be significantly big. Now, the other thing about evaporation ponds are they're storing salt is what they're doing. They're huge. And in the summertime they look like they're way oversized because they look like you got a lot of dry surface.

In the wintertime the water's rising. So you have to size them so you can take all the cycles. The wet years, the dry years. It's a fairly complex analysis to size these things.

And in the meantime you get a fairly large load of salt, 30 years of salt accumulate in these ponds. Sometimes the ponds have to be dug out, taken out of service and dug out. So they're not as simple as they look.

And for that reason a lot of people don't like to build something this big. And you also have to have the acreage to do it. And they only make sense in very dry climates. This would be crazy on the coast, because there's not enough land, and it has to be flat. That's the other rule for evaporation ponds. As soon as you start getting a wavy surface the costs go out of sight, and they don't make any sense.

Okay, let's go to the next one. Now, this is the brine concentration I told you about. Now, interestingly enough, you can reduce the waste fairly significantly. What it does is it takes you to one-tenth of what you would have had if you didn't have a brine concentrator.

But it takes about a megawatt of power to drive it. And that's power off -- that's power before you sell it. That's power off the grid before it's sold.

You do generate a very high quality stream of water which can be used for boiler makeup, a little extra treatment for boiler makeup, gas turbine injection for NOx control. Those are some typical uses for that water.

And then the next one shows, if we just want to get rid of the evaporation pond completely, you go to a crystallizer. And you end up with a pile of salt at the end of the day.

And from what I've seen salt is generally it's a nonissue. It's just salt. A lot of people just leave it on site; some people pay somebody to take it away and dispose of it, you know, legally, by disposing it to a disposal site. So, those are the issues.

Now on the next page I can just show you some ideas of what these numbers look like. The option one is just an evaporation ponds. You're looking at for a 500 megawatt plant, ten cycles of concentration, and that may require some treatment to get there because the water's highly degraded. You're looking at 94 acres of ponds in the central valley versus 63 acres in the desert.

And then you can see that the ponds get

dramatically smaller as you put an evaporator in. And then if you have a crystallizer, you have no ponds. And then you have a power requirement also, almost a megawatt for an evaporator for this plant. And 1.2 megawatts for an evaporator crystallizer.

MS. TOWNSEND-SMITH: Are there many plants using a crystallizer?

MR. DiFILIPPO: Yeah, there's probably four or five out there right now, all over the place. There's one -- there's how many, Joe, in California? Two? One?

MR. O'HAGAN: Well, the High Desert is certified. It has a crystallizer. Sutter is going to use a crystallizer for the cooling tower blowdown clearly, but the steam cycle blowdown, HRSG blowdown. LaPaloma has a crystallizer.

LaPaloma has a crystallizer. Sutter has a crystallizer for the HRSG blowdown. And LaPaloma has a crystallizer.

MS. TOWNSEND-SMITH: Well, any in operation? I mean, I know they were all --

MR. O'HAGAN: Not that I'm aware of in California. Elsewhere, though, I know Calpine has a couple units up in the Pacific Northwest that use crystallizers. And back east there's quite a few.

MR. DiFILIPPO: The use in other --

MS. TOWNSEND-SMITH: Okay, because I remember --

MR. DiFILIPPO: They're used in other industries extensively to recover ore, for instance. You'll have a solution of ore and water, and they actually use them in other applications, as well.

They've been around for years and years and years. This is sort of a new application for this technology. But Joe's right, it's an old technology, it's been around for a very long time. And, you know, I don't think there's a lot of risk involved in specifying one for a plant because they should work.

And then on the last page I just tried to put some costs together based on -- I got some costs for evaporators and crystallizers for one of the major suppliers of this equipment. And they're very reputable.

And you can see there's a dramatic difference in the cost. If you just went with straight evaporation ponds, you know, they cost about, my estimate was about $350,000 an acre. And that's flat land, and that's a pond that won't leak. It has to be certifiable, won't leak. It has to be engineered. It's lined. It has sensing devices below the surface, below the bottom of the pond to detect any kind of leakage.

So it's a fairly significant expense. And you can see that it does make sense to go with evaporation technology especially in the central valley, crystallizing technology, because it's even a little cheaper, because you don't have as good evaporation there.

In the desert, because the evaporation rate is so high, it's almost a wash. It doesn't make -- to me it doesn't make sense to put a crystallizer in when you can put a tiny little evaporation pond in.

That concludes my --

PRESIDING MEMBER LAURIE: Question. When you go back to your note regarding the available types or sources of recycled water, and then you look at those areas of California that are more likely to have fresh water shortages. And you look at the sources of the alternatives.

Do they match? That is, in those

geographical areas where there may, in fact, be greater pressure on water services, are you just as likely to find alternative recycled sources as anywhere else? Or is that too difficult to determine?

MR. DiFILIPPO: Well, I know for the central valley there are a lot of salt sinks. And some are not that degraded, the waters. Maybe they have a couple thousand TDS of salt content, but they're useable. They're sort of like slight brackish water.

So the central valley has got some opportunities for this kind of water use.

The high desert, I'm not sure. I've done a couple of designs in the desert. And we used adjudicated water rights. I mean we actually owned the rights to the water, so we just used the water rights we had for that.

But I can't answer for the high desert.

PRESIDING MEMBER LAURIE: Okay. Gentlemen, thank you very much.

What I'd like to do is hold off on questions for a bit, because I, I'm sure like a lot of you, have to get to the airport and I don't want to rush our next presenters.

So, if we can hold our questions for awhile. Are you gentlemen going to be here for a few minutes, anyway? Okay. Thank you very much.

MR. O'HAGAN: Thank you, Commissioner Laurie. The next panel, panel 3, is dealing with water policy. And I think that hopefully this morning's presentations and the presentation by Mike and John raise some serious policy question issues that we know that speaking of dry cooling, certainly technologically is feasible, does present certain costs and efficiency losses, maybe even some system reliability or capacity concerns.

Also using degraded water, you know, if things aren't available is it ever appropriate to use potable water, or potable quality water. And hopefully that these things will be touched upon, or certainly discussed later today.

The three speakers we have lined up for the water policy discussion are Gerald Meral, Michael Jackson and Kaitilin Gaffney.

PRESIDING MEMBER LAURIE: Thank you very much.

MR. BUELL: I believe Jerry Meral is not here yet, but we can proceed with these speakers.

PRESIDING MEMBER LAURIE: Okay. Good

afternoon, folks. Thank you for joining us.

MR. JACKSON: My name is Michael Jackson; I'm a water attorney. And I represent the Regional Council of Rural Counties, which is 28 northern California counties or Sierra counties, both on the central valley floor and in the mountains above.

PRESIDING MEMBER LAURIE: Know them well, just had a meeting with your energy folks the other day.

MR. JACKSON: Well, thank you very much. We appreciate it, that's where we've been.

Basically our view is that there is ample water for the siting of these plants above the delta diversion facility. That would mean the mountains, the foothills, the Sacramento Valley, but not probably in the delta, itself, or in the San Joaquin Valley.

The reason is that the water system is not sized or located in a way that water can be distributed equally about the state. And the problems are getting worse, not better.

And consequently, we feel that potable water should not be used in a situation in which there are other alternatives.

And that as I listen to the testimony in regard to evaporation ponds, salt is the major problem in water in California. And the use of evaporation ponds, either at the Kesterson facility or at other facilities in the San Joaquin Valley has made it very clear that not only is the groundwater something that can be polluted by evaporation ponds, and has been, but there is a tremendous problem with the Pacific flyway even if the evaporation pond does not leak.

The Kesterson experience has been one that has been repeated all over the west in places where evaporation ponds have been used, and basically unless you can protect avian species, the flyway, itself, evaporation ponds are destined to fail.

Consequently I was very glad to see the information about crystallizers, about dry methodologies. It seems that in terms of a long-term future, it would be appropriate to use only presently polluted sources for water supply generally depending on the amount of treatment you would use, the TDS number that folks are trying to reach is below 500.

So, basically any waters over that

amount would be appropriately use, I think, for this kind of use for the state.

But the evaporation pond technology in the San Joaquin seems to me to be something that you would not only have a source supply, but a disposal supply. And an existing condition that the water system has never been able to deal with.

And consequently expanding it now to both energy and water in the San Joaquin Valley would be a great step backward in our opinion.

PRESIDING MEMBER LAURIE: Joe, do you know which applications we have, if any, for the San Joaquin?

MR. O'HAGAN: That have evaporation ponds?

PRESIDING MEMBER LAURIE: For applications for power plants. Do we have any that are located in the San Joaquin Valley?

MR. O'HAGAN: Yes. We just certified Elk Hills Power Project. There's the Midway-Sunset facility. Those are on --

PRESIDING MEMBER LAURIE: Yeah, but that's down south, right?

MR. O'HAGAN: Right, San Joaquin.

PRESIDING MEMBER LAURIE: Is that still

considered -- how far south does San Joaquin Valley go?

MR. O'HAGAN: Tehachapi.

MR. JACKSON: The San Joaquin Valley actually technically, in terms of the hydrology, only goes to Fresno. But the Tulare Basin has the same problems with salts building up to the level now that many of the growers are beginning to lose ability to grow crops because of the buildup of salts now.

And to add to that, if there is another place to site these facilities, -- I mean I'm sure there are micro-sites that would be able to operate on groundwater that was not potable or not usable for agriculture.

But in general, I think that's something that ought to be looked at very closely because this water is, as power, becoming more and more expensive. And transferring its use from the environment and agriculture in an area that is that critical to both the economy and the environment would seem to me to be something that ought to be addressed carefully in terms of siting.

PRESIDING MEMBER LAURIE: One issue, and

this is speculation on my part because I haven't had a chance to chat with you about energy water policy in the rural counties. But in the rural counties water is always an issue. It's in the rural counties that often claims source of origin.

MR. JACKSON: Yes.

PRESIDING MEMBER LAURIE: Is that the right terminology?

MR. JACKSON: I spend most of my day talking about that.

PRESIDING MEMBER LAURIE: Well, I've been in El Dorado for 28 years, so I --

MR. JACKSON: Yes, sir, so you understand.

PRESIDING MEMBER LAURIE: -- I understand the issue. And yet, power plants, as we've noted, are generally -- well, but for down south we haven't had any applications for power in -- I don't know, when I think of RCRC membership, does that include Kern and --

MR. JACKSON: It does not include Kern. Inyo and Madera are our southernmost counties. We come up to Fresno city limits.

PRESIDING MEMBER LAURIE: Okay.

MR. JACKSON: And go to the Oregon

border.

PRESIDING MEMBER LAURIE: I'd be interested in having a further discussion with you about the relationship between rural counties and smaller power plants. I'd also be interested in seeing when we're going to get an application for a power plant really in the San Joaquin. It will not happen in the foothills, I can't imagine. Well, yeah, I guess I can imagine, but --

MR. JACKSON: Can't imagine it being built.

PRESIDING MEMBER LAURIE: If you think San Jose is bad folks, wait till you deal with mountain people.

MR. JACKSON: There are actually possibilities in the mountains, I believe. But we would have to be extremely careful. There is abundant water. There are industrially zoned sites from what we used to call a timber industry. And most of those facilities have power to them, and they're abandoned. And they would be very quick in all siting problems except water.

Now, if the state has a policy that would allow -- I presume the State Water Board was here this morning and explained their policy under their order, where basically there's a series of steps down to where you get to the kind of quality water we have.

And we agree that as best possible we ought to use the worst possible quality that will fit the purpose. But, in our areas, in the mountains, along some of the major transmission lines, because of the fact that the hydro plants are located there, as well, there are sites, bombed-out industrial sites, that would be quite appropriate. And there are people there who believe that energy is a potential economy.

PRESIDING MEMBER LAURIE: What about gas?

MR. JACKSON: There are gas pipelines available in some places. We have not looked at that and would be very much interested in working with you or anyone else to take a look at logical places to site next pipelines, near transmission lines, on previously existing industrial land. And we think that combination would be the fastest.

PRESIDING MEMBER LAURIE: Excellent, and thank you, sir, very much.

MR. O'HAGAN: Sorry, I sort of subsumed

the Tulare Basin into the San Joaquin Valley.

PRESIDING MEMBER LAURIE: No, that's okay.

MR. JACKSON: All politicians do, so it's okay.

(Laughter.)

MR. O'HAGAN: Thank you. One thing we did have one project that was going to be filed in Livingston, I think it was believed to have been a Modesto Irrigation District project, but it was never actually filed.

But, Mr. Gerald Meral is here now. And so, introduce --

DR. MERAL: Thank you very much.

PRESIDING MEMBER LAURIE: Dr. Meral, how are you this afternoon, sir.

DR. MERAL: Very good, thank you for the invitation to appear before you.

You're honing in on an area that's very important, increasingly important, I guess, with all the siting that's going on. And the water board, of course, has paid attention and you've heard from them extensively on this.

But, our sense is that given a drought situation, if a power plant has been allocated a supply of fresh water that can be used for other purposes, in a drought you've got a double whammy in a sense. Most likely that power plant is going to have to run more because there's less hydro available, and also water's in less supply.

So you've elevated that power plant to one of the highest and best uses by accident in a sense. And that's all the more reason to try to the utmost to prevent dedication of these fresh water resources to new power plants.

And we've been a little bit involved in some controversies over this because sometimes the power plant operators rightly feel that if they're forced to use reclaimed water, there are going to be costs associated with that that they wouldn't have if they just opened up the tap.

And while the Energy Commission obviously has a lot to do, we would encourage you to perhaps become involved in attempts to find additional subsidies for the use of reclaimed water such as proposition 13 provided. We have extensive funds in proposition 13 to pay for the use of reclaimed water for these kinds of industrial facilities.

I'm pretty sure that Mr. Costa will

introduce another water bond. And this might be an opportunity for you, at least through your staff, to make an appearance to urge increased funding in the area of recycled water. Because it will become available for the sites that you're going to have to site, the plants that you're going to have to site.

And really is probably one of the most realistic alternatives in many parts of the state that, you know, do have this kind of water supply available.

It's very hard for you to turn down a power plant because it's using fresh water. If it's the only alternative, you're probably going to have to site it.

PRESIDING MEMBER LAURIE: Well, in addition, one of the challenges that I think we face in our hearing process is there's no Energy Commission policy dealing with the mandatory use of the dry cooling or alternative system.

We really only get to that question if upon environmental review we find that water service is significantly impacted.

As we had chatted about earlier today, the Commission relies on readily available data normally for those purposes. And more often than not the data reflects the views of the local water districts, that there's an adequate supply of water to serve that project.

So if a local government agency says to us, we'll serve, then the Energy Commission would be challenged to say well, we have data in front of us that says from a statewide perspective there's a bigger question here.

And so that's a fundamental issue that we face probably in every case.

DR. MERAL: Well, you're right on point with a certain lawsuit that Mr. Jackson and I are intimately familiar with.

(Laughter.)

DR. MERAL: Because, as you may know, we brought a suit regarding the state water supply, state water project supply, PCL v. DWR, and the appellate court said that the state should stop relying on what in a sense you're referring to, which is paper water. Water that has been contracted for, but which the state, at least, is currently unable to deliver.

And we are hoping, as this suit is perhaps settled or further litigated, that we can get you better information about what's really available. Because what they tend to do, just as you're saying, is well, there's a contract for 2.-whatever-it-is-million acrefeet at NWD, therefore the water's going to be there. In fact, the reliable delivery is half of that.

And so we are totally in sympathy with that concern. You and many other planning agencies have the same problem.

But we would urge you to at least look, when you're in the state water project service area, which is not everything you're dealing with, at what the state system can reliably supply. Because what you're getting back from the local planning agency is their full contract, as opposed to what DWR in bulletin 132, which is publicly available, says actually can be delivered.

So that is one way you can probe a little more deeply into what's really there.

PRESIDING MEMBER LAURIE: Okay, thank you.

DR. MERAL: I think, you know, from our point of view our sense is there's so many demands for water, environmental demands, industrial, agricultural, and so on, that to the extent power plants can avoid making additional demands because they are so rock solid and so uninterruptible, if I may use that word, we urge you certainly to try to either get the technology to the point where they need little or no water, or get them onto the reclaimed water source, which is really a good source for most of these power plants.

They don't need superb quality the way perhaps Silicon Valley does. They can use recycled water, especially if it receives tertiary treatment. And to the extent you can help us in the Legislature get more funds for that, it'll make your job easier, as well.

PRESIDING MEMBER LAURIE: Thank you. Question for you. We talked a little this morning about how available water resources are used in the something like 45 percent of available resources, available for environmental purposes.

We are at the point in the processing of power plants where very serious interests are clashing. Air quality versus power. Water supply versus power. Community design versus power, et cetera.

On the issue of environmental waters, what percent of that set-aside is available for flexible use? I'm not asking you to negotiate here.

DR. MERAL: No, I understand.

PRESIDING MEMBER LAURIE: Because I honestly don't have any understanding of where that water goes.

DR. MERAL: One of the problems with that figure, which would be a statewide figure essentially, is that the vast majority of water that's considered dedicated for environmental purposes is actually in the wild and scenic rivers of the north coast, the Eel, Trinity, Klamath and so on, Smith.

And that water, even though it's been dedicated in the wild and scenic rivers, would be available for power plant cooling and so on by appropriation. If someone showed up in Crescent City and said they wanted to build a power plant, there's nothing in the Wild and Scenic Rivers Act to prevent that. I mean it would have to be done in the right way and so on.

So the answer is probably the vast majority of it, but it's not in the right place. The water that's been dedicated in the central valley for environmental purposes is a very small fraction of that, and that's a lot less flexible because the Sacramento River, which is the main source of that water, is so under stress already that -- and what's more, it, too, is largely in the wrong place. I mean in terms of the diversions out of the channel. That it's probably not overly relevant to most of your discussion. Because that water is not where you want to site the power plants, by and large.

That's not entirely true, but by and large that would be the case.

MR. JACKSON: The other thing to add to that is that I live in Plumas County, which is the watershed for the state water project. And it's also PG&E's stairway of power in terms of hydroelectric.

And so while you have numbers that indicate that there's 3.2 million acrefeet of water that falls in my county, and we only use 3000 acrefeet of it, in the rivers you are presently using 98 percent of our river for your hydropower. Because only 2 percent of the water flows in the river.

DR. MERAL: That's true, because that water is then available for use downstream after it goes through the power plants.

PRESIDING MEMBER LAURIE: In a hydro project what percentage of water is returned to the waterway?

MR. JACKSON: Almost none.

DR. MERAL: Well, or all. I mean at the end of the --

MR. JACKSON: Yeah, after -- when you arrive at Lake Oroville --

(Laughter.)

MR. JACKSON: -- it all appears. But in terms of the environment, in my county at least, on the North Fork of the Feather River, except for four holding ponds, the water is always in tunnels.

PRESIDING MEMBER LAURIE: So it gets diverted and is owned by downstream users?

DR. MERAL: Eventually, in most hydro there is a later beneficial use of the water, except for some environmental regulations the water board or someone else has applied.

PRESIDING MEMBER LAURIE: Thank you.

DR. MERAL: Thank you.

PRESIDING MEMBER LAURIE: 'Afternoon, Ms. Gaffney, how are you?

MS. GAFFNEY: Thank you. My name is Kaitilin Gaffney and I'm here today speaking on behalf of the Center for Marine Conservation. We're a national environmental organization that's dedicated to ocean protection. So I'll be speaking from a slightly different perspective, and maybe one that's good to have after all this discussion about inland water and supply. I can speak up for the coasts and the ocean water supply issues, which may be good, since we may be shifting the pressure towards the coast, since we don't have the same supply issue there.

But ultimately what I'm going to ask you is I think something that you've heard several times, and the previous speaker also suggested, to look towards alternatives that do not require large volumes of fresh water, estuarine water, or ocean water. So, basically the same plea.

And my suggestion, in response to the question of how to expedite bringing new power capacity on line in California, how to deal with environmental constraints, is to try to solve the environmental problems so that community doesn't have to oppose a plant, as opposed to trying to figure out ways to speed up the process without taking those concerns into account.

We heard a lot of discussion this morning, and in the earlier session this afternoon, about dry cooling. And I really think that that is where we need to be looking in the future. We submitted comments on the EPA proposed regs asking that dry cooling be considered in all environments, not just in near-shore coastal waters, but also offshore, because we think there's strong evidence that power plants, even those that draw from offshore coastal waters, have very severe impacts on the environment.

PRESIDING MEMBER LAURIE: And what are some of those? What would some of those impacts be?

MS. GAFFNEY: I'm glad you asked.

(Laughter.)

MS. GAFFNEY: And I will be submitting written comments with more detail and background.

The statistics are pretty staggering, 70 trillion gallons of water go through power plants every year in this country. Certainly by volume most of that is coastal waters, ocean water.

The concern that I have is not a supply issue, but that water is not just -- it's not just a mechanism for cooling power plants. It's an ecosystem. It's habitat. And contained in that water, both in fresh water systems and in the ocean systems that I'm more familiar with, are fish, are fish eggs, are fish larvae, are invertebrate eggs, are invertebrate larvae. There's all the life that is found in rivers and the ocean.

And typically the consequence of going through a power plant for those organisms is not good, to put it mildly.

I'll give you some statistics from San Onofre. In a normal year 110 tons of midwater fish are entrained and 41 percent of those are killed as they go through the San Onofre plant.

Cooling water intake has reduced kelp beds off of San Onofre by 60 percent, resulting in a 70 percent decline in the abundance of kelp-associated fish species.

I have pages and pages of examples from power plants from all over the country. Obviously the impacts differ from plant to plant, different areas of the state and the country have different impacts.

But the take-home message is that even

though ocean waters are sort of the second priority and considered, given some kind of preference in terms of cooling water under state policy, there are serious impacts associated with using huge volumes of ocean water for power plant cooling.

And to the extent that we can reduce that volume or eliminate that volume, we would have a very immediate and direct benefit on those coastal ecosystems. And those are systems that are facing increasing pressures from land-based pollution, from over-fishing, from a variety of different human sources.

So it's not as if this is the only thing that they are trying to grapple with. We have -- CMC was recently involved in a petition to actually list an ocean fish species under the Endangered Species Act, the bocaccio rockfish.

We are looking at very serious pressures in particularly our near-shore coastal environments in California. So power plants are one more thing that those systems have to try to deal with. And the volumes are enormous. Hundreds of millions of gallons a day being taken out of frequently near-shore estuarine environments that are particularly sensitive for the species that use them.

PRESIDING MEMBER LAURIE: Given your organization's experience, what is the ability of a -- if you know, of a modern power plant to mitigate its impacts on the ocean ecosystems?

MS. GAFFNEY: Well, we heard some discussion this morning about how much better new plants are compared to the older plants. And I think it's true that we're looking at better technologies, but a lot of those plants, you know, plants that went in in the '50s or '60s, I would hope that we're looking at better technologies.

The fact remains that the impacts are very very high. You're still taking -- even if the volume of water per unit of energy has dropped because of increases in efficiency, when you're looking at, you know, 800 million gallons of water a day and everything in it, the impact is still great.

And as we need more energy the net continues to grow, even if we're becoming more efficient.

I think we probably are improved from where we were several decades ago, but it's still a very serious problem.

DR. MERAL: Could I add just one thing in addition to that. Just to quantify it, Friends of the Earth and the Earth -- Institute brought a lawsuit against Edison regarding the marine impacts of San Onofre. And the mitigation settlement was in the tens of millions of dollars.

And much of the mitigation money ended up being spent in even San Diego County, they had to go that far south to find places to do the mitigation. It was quite difficult.

Another concern is that there is, of course, a lot of problems with closures of beaches in Huntington Beach in the last whole year, actually, much of the beach was closed during that time. There's now some indication that simply the drawing in of cooling water by power plants in that area has brought the discharge of pollutants that was very far offshore, brought it much closer to the beach, and perhaps contributed to the enormous economic damage that was done when Huntington Beach closed its beaches.

So, we're finding more and more problems with these kind of marine intakes for cooling water.

MS. GAFFNEY: I agree completely. I think that's a very good point. That a) these are very complex systems where it's difficult to understand what the true impacts will be over time, over 30, 40, 50 years, lifetime of a plant. And so you see, in the case of Huntington Beach, problems that no one would have predicted. And some still don't -- they're still debating over what's going on. But there are unexpected consequences.

And so I guess the basic message that I'm trying to get across is that you cannot remove huge volumes of ecosystem without having a serious impact on the environment. And if there's an alternative to doing that, by using technologies that use greatly reduced water sources, you know, just closing the system so that the water's recirculated can reduce the need for ocean water by 95 percent. That's not even dry cooling.

So, don't ignore the application of these technologies to the coastal environment and the ocean-based power plants. Obviously there are community concerns related to new power plants on the coast that have nothing to do with marine biology, visual impacts and the tremendous affection Californians have for their coastline, so that when new power plants are proposed in coastal areas, the outcry is going to be tremendous.

I think we need to look at ways that we can produce energy closer to where it's being used, to try to limit transmission losses. And having huge plants on the coast that they have to get their energy inland to where it's being used, you know, may not be the answer for the future. Although it was the way we did things in the past.

PRESIDING MEMBER LAURIE: Well, in fact, one of the challenges is that the population on the coast is at its maximum, and therefore the people are moving inland, which requires more power plants to be located inland where the demand is, but not necessarily the resources, makes for interesting energy planning.

MS. GAFFNEY: Right, no, I agree. I would just argue we don't have the resources on the coast, either.

Dry cooling has been used very successfully. It's becoming more popular around the world. There are 600 plants right now that use dry cooling around the world. They've been used in areas with climates that are very hot and arid desert areas, in cold areas. I think it's a very realistic technology, and one that we should be looking at, because it is capable of reducing so many of these problems.

PRESIDING MEMBER LAURIE: Thank you, Ms. Gaffney, very much. Gentlemen.

At this time I would make the microphone available for members of the public that wish to comment or ask questions. And I thank the panel tremendously, very well done.

Any member of the public wish to offer comment?

Ms. Townsend-Smith, do you have any questions or comments?

MS. TOWNSEND-SMITH: None, no.

PRESIDING MEMBER LAURIE: Okay, Mr. Tomashefsky.

MR. TOMASHEFSKY: No.

PRESIDING MEMBER LAURIE: As we've commented earlier, the purpose of this hearing is to talk about the challenges of licensing power plants in the future, and what barriers might exist.

This issue is one of a series of issues

that we are examining and it's our intent to issue a report roughly during the month of April. In light of the fact that this is not a Legislative mandate, if it's not issued until May, nobody will care.

But these questions are important. And obviously what we're finding is that again, for the very -- maybe not for the very first time, but more apparently now than ever before, different interests are being pressured and are in direct conflict. And there's going to have to be some policy decisions determined.

Absent any questions or comments, I would adjourn the meeting. And I thank you all for your attendance.

(Whereupon, at 2:45 p.m., the workshop was concluded.)

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CERTIFICATE OF REPORTER

I, VALORIE PHILLIPS, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 14th day of February, 2001.

VALORIE PHILLIPS